COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:

Preparation of the 2009 Integrated Energy Policy Report	)	Docket No. 09-IEP-1O
Options for Maintaining Electric System Reliability	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

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Committee Members Present

Suzanne Korosec, Cec
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Steve Stmarie, Cpuc
Susan Brown, Cec
Jon Bishop, Wrcb
Michael Jaske, Cec
David Vidaver, Cec
Dennis Peters, Caiso
Robert Strauss, Cpuc

Also Present

Laurie Tenhope, Cec
John Bohn, Cpuc
Kristy Chew, Cec

Panel 1: Environmental Agencies

Mike Jaske, Cec, Moderator
Jon Bishop, Wrcb
Mohsen Nazemi, Sciqmd
Mike Tollstrup, Arb
Al Wanger, Ccc

Panel 2: Electric Generators

David Vidaver, Cec, Moderator
Eric Leuze, Rri Energy
Sean Beatty, Mirant

Panel 2 Continued,

Randy Hickok, Dynegy

Eric Pendergraft, Aes

Jesus Arredondo, Nrg

Panel 3: Utilities

Mike Jaske, Cec, Moderator

Mark Minick, Sce

Gordon Savage, Sce

Mark Krausse, Pg&E

Curt Hatton, Pg&E

Rob Anderson,Sdg&E

Eric Tharp, Ladwp

Panel 4: Environmental Community

Mike Jaske, Cec, Moderator

Deborah Sivas, Stanford Environmental Law Clinic

Angela Haren, California Coastline Alliance

Joe Geever, Surfrider Foundation

Bill Powers, California Coastline Alliance

Leila Monroe, National Resources Defense Council

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P R O C E E D I N G S

MS. KOROSEC: Good morning everyone. I'm Suzanne Korosec. I lead the Energy Commission's Integrated Energy Policy Report Unit. Welcome to today's workshop on options for maintaining electric system reliability when eliminating once-through cooling power plants. It's being conducted by the Energy Commission's Integrated Energy Policy Report or IEPR Committee in conjunction with the California Public Utilities Commission and the California Independent System Operator.

Unfortunately, Commission Bohn was unable to join us today. I understand he's not well, but in his place he's being ably represented by his advisor, Steven St. Marie. Welcome, Steven. And also we'd like to welcome Mr. Mansour from CA ISO. We really appreciate having you here today.

Just a few housekeeping items before we get started. The restrooms are out the double doors and to your left. There's a snack room on the second floor at the top of the stairs under the white awning. And if there's any sort of emergency and we need to evacuate the building, please follow the staff out the door to visitor's park, which is diagonal building and wait there for the all clear signal.

Today's workshop is being broadcast through our

WebEx teleconferencing system, and for parties who are using that system who would like to ask a question or speak through the comment period, you can used the raised hand feature or you can send a chat email directly to the WebEx coordinator.

Just a little brief context before I go over today's agenda. The Energy Commission is required by statute to develop and IEPR every two years that provides an overview of major energy transit issues that are facing the state along with policy recommendations to help the state meet its energy related goals. The issue of once-through cooling in power plants had come up at every IEPR since the first one was published in 2003.

The 2003 IEPR adopted a policy on water use in power plants requiring new plants to use degraded or recycled water or an air-cooled system and to use zero liquid discharge technologies unless doing so would be shown to have significant adverse environmental impact or to be economically or otherwise infeasible. This was intended to reduce the amount of fresh water and its use in power plant cooling systems and the impact of these systems on the environment.

The 2005 IEPR raised the issue again and noted the need for additional study of the ecological effects of once-through cooling and directed the Energy Commission to work with other state agencies and address these issues in the broader context of protecting the state's coastal marine ecosystems.

The 2007 IEPR discussed legal challenges associated with the use of once-through cooling in existing power plants, and noted that licensed applications for new power plants proposes the use of once-through cooling could be substantially delayed or denied because of those challenges. The 2007 IEPR also noted that there are potential liabilities impacts associated with these legal challenges since two-thirds of California's coastal power plants are located in Southern California, which already faces reliability challenges due to the number of aging plants plus the shortage of emission credits that are available for new plants in that region.

For the 2009 IEPR, we're once again looking at this issue and this time really focusing on the impact of the reliability -- excuse me, on reliability of the proposed regulations to restrict once-through cooling. The goal of our efforts is to implement a once-through cooling mitigation policy for existing generators that's integrated with planning and development of replacement infrastructure that will be needed to support reliability. If owners of plants that use once-through cooling decide to retire their plants rather than meet the new requirements, you could a have severe effect on reliability particularly in Southern California given the recent court decisions about the priority reserve credits and the uncertainty about whether new plants could permitted in the South Coast Air Management District's airshed.

So the purpose of today's workshop is really to get feedback from all of you on how the state's energy agencies may need to modify our existing planning procurement and permitting processes to allow the development of new infrastructure like generation or transmission or other system elements that can reduce the reliability impacts of the proposed once-through cooling mitigation policy.

So I'm just going to briefly go over today's agenda. First, we'll have opening comments from the Dais followed by a presentation by Jon Bishop from the State Water Resources Control Board on the environmental impacts of once-through cooling and mitigation proposals.

Next, we'll have an overview of reliability issues from the Energy Commission, CA ISO, and the CPUC staff, followed by a one-hour panel to hear from the state's environmental agencies. We hope to take our lunch break at 12:30 and resume at 1:30, followed by three additional one-hour panel discussions, one with the electricity generators, one with utilities, and one with the environmental community.

And once we've completed the final panel discussion, we'll take time for public comments. First, from those in the room and then from parties listening on the phone, and then Dr. Jaske will do a brief wrap-up of the day.

We do ask that parties wishing to speak during the public comment period today fill out a blue card. These are available on the table out in the foyer. You can give those to me throughout the day, and I'll pass them on to the Commissioners. Depending on the number of parties wanting to speak, we may need to limit the time for each party. We'll see once we start seeing the cards coming in, but please know that we do value your input and we want to try to fit everyone in who wants to talk today.

So unless there are any other questions, I would like to pass this on to the Dais for public comments.

COMMISSIONER BYRON: Thank you, Ms. Korosec, and thank you all for being here particularly my colleagues from the ISO and the Public Utilities Commission. Thank you for being here.

I think those of you that are in the know on this particular issue understand the significance of the implications of the once-through cooling issue. And I can tell by your attendance here today that we're going to have a very good discussion around this topic. There's a lot of effort that's been underway at the energy agencies and the Water Resource Control Board on this particular issue. We have met numerous times on this issue as well here amongst the PUC, Energy Commission, and the Independent System Operator.

As Ms. Korosec said, this workshop we're really interested in the input from the various stakeholders about the reliability issue associated with implementation of the once-through cooling mitigation policies. And we're not going to debate the virtues or the implications of the actual once-through cooling rule that's being promulgated, although I did find myself instead of counting sheep last night before I went to sleep trying to calculate the cubic meters of 15 billion gallons of water a day that has passed through all of these power plants.

I think I'll keep my remarks short. I'm very interested in hearing from all of you, and we'll make sure there is ample time for public comment. I'd like to ask if any other of my folks at the Dais would like to say anything. Mr. Mansour?

MR. MANSOUR: Thank you, Commissioner. Thank you, Commissioner. As always, I want to thank you and the

Energy Commission for staying on top of this issue. You've always demonstrated really keen interest in what matters to the state and particularly this industry.

As most of you and all of you know, the ISO's mission states a commitment to reliability, efficient market, which indicates reasonable cost, and alignment of federal and the state policies. In many cases, they are perfectly aligned. In some cases to meet all three or called to strike the right balance, it's an order. Unfortunately or fortunately, depending on how we look at, reliability is not a compromise. Today's discussion is all about this, striking the right balance.

And while we commit to facilitating the state policies, it is important to recognize the challenge of operating a grid with a massive amount of intermittent resources while restricting the operation of the existing facilities so as needed to backup is a major challenge. No one knows more than California that when lights go off or rates have gone higher, nothing else matters and everything else changes. So for us to actually make sure that all (inaudible) stay intact and achieve their purpose, we have to make sure that the lights do not go off and prices stay reasonable.

Our role is to find that balance and provide the supply, reasonable cost, and environmentally friendly future. I look forward to the rest of the day.

COMMISSIONER BYRON: Mr. St. Marie?

MR. ST. MARIE: Thank you, Commissioner Byron, for having me. I'm Steve St. Marie. I work for Commissioner Bohn. Commissioner Bohn sends his regrets. He is quite ill and we're all better off for not having him around here, as well as he's better off being at home. I'll do my very best. Thank you.

COMMISSIONER BYRON: Thank you. Ms. Brown?

MS. BROWN: I'm Susan Brown. I'm representing Commissioner Jim Boyd, who unfortunately couldn't be here today, and I can assure you that this is an issue of utmost importance in his mind. Commissioner Boyd was an air regulator for many years. He's very sensitive to the confluence of some of the issues that we've heard mention already today.

We have -- We're assigned to something, I think, ten or eleven power plant siting cases, and each of these brings forward the need I think to integrates what often appears to be conflicting state policy goals and single systems approach, so I'm hoping to get educated further today. And Commission Boyd would have like to have been here if he could, so thank you.

COMMISSIONER BYRON: Thank you, Ms. Brown. And also with the Dais with us today is my Senior Advisor, Ms. Laurie Tenhope. Laurie, did you have anything you wanted to say?

MS. TENHOPE: No, thanks.

COMMISSIONER BYRON: All right. Thank you all so much for your comments. I think we're going to go ahead and get started with the agenda if I may introduce our first speaker, Mr. Jon Bishop, Statewide Resource Control Board.

Mr. Bishop, thank you for being here this morning. I'm sure you're going to put this all in perspective for us.

MR. BISHOP: Well, I will try. Thank you very much for having me here today.

What I plan to do today is give you all a background on where we are and why we're looking at once-through cooling policy for the state, and then touch on the approach that we're proposing at this point.

Here we go. All right, now I've got this figured out. We currently have approximately 19 plants that use once-through cooling. That's something like 15 billion gallons per day sent through these cooling systems. These plants are located all over the state from Humboldt County down to San Diego. It just depicts and some of the grid infrastructure on there. I'm not going to go through each plant at this time, but this is just to give you an idea of where they are.

The reason that the State Water Resources Control Board has been looking at the statewide policies for mitigating the impacts of once-through cooling is that there are some serious impacts. We have thermal discharge impacts, which include not only the thermal but also the waste associated with the chemicals used for treatment in the plant and sometimes human waste that's comingled with discharge. We have impingement, which is the act of getting large organisms impinged or trapped on the screens, the intake screens for the plant, and then entrainment where the small larvae are actually brought through the plants itself, and then are killed with the heat systems.

Just to give you some idea over the last few years, we have been working with many of the energy companies to come up with estimates on these impacts. Something about 97,000 pounds of fish and macroinvertebrates are impinged each year on these plants. We have a smaller but still significant number of large organisms, marine mammals, and sea turtles, more around 50 to 60 of those, and then a very large amount of fish larvae and eggs that are entrained each year. We also have the impact associated with the thermal discharges.

I just want to take a minute and think about this. We have a -- If we have fish kill associated with the discharge from one of our plants, that usually makes the front page of the paper. We don't -- We have zero tolerance for fish kills in most of our discharges, but we expect it from these once-through cooling plants. It's part of the operation. It's something that we need to be addressing and looking to reduce.

Our goal is to develop a statewide policy to minimize these impacts. At the time, the last thing that we want to do is be responsible for an impact on the grid. I really do not want to add to my résumé that I was in charge of policy that shutdown the grid and turned out the lights in California. So we have been working --

COMMISSIONER BYRON: None of us want that one.

MR. BISHOP: -- to try to mitigate both the impacts of once-through cooling and mitigate the impacts of moving away from once-through cooling.

I will go into a little bit more detail about how we've been doing that in a minute, but we've been working with representatives of your agencies and others to bring in a different perspective than just the State Water Board's perspective.

Why are we here? Well, the Clean Water Act, Section 316(b), requires that we look at the design, construction, and best available technology for minimizing the adverse impacts. Also, the California Water Code or the Cologne Act requires us to do the same thing. It's slightly different language but essentially under both of those requirements, we are charged with the task of minimizing the impacts from once-through cooling on the marine environment.

The way this works is that under both -- under 316(b) under the State Water Board, we are required to permit once-though cooling power plants under an NPDES, which is a National Pollutant Discharge Elimination System Permit. That's the Clean Water Act permitting authority.

There are not any existing federal regulations that are in place or state regulations for how that would be accomplished for existing facilities. So for the last 30 years, the Regional Boards have been using best available -- best professional judgment to look at what is the best available technology for minimizing those impacts.

We are under a requirement to renew these permits on a five-year scheduling. The Clean Water Act NPDES permits are good for five years, and if those go beyond that five-year period, they are extended administratively, which means that the previous permit stays in place until a new permit is adopted. Many of these permits are -- their permits are expired.

The State Regional Boards have been waiting on how to best address that problem, and I'll be blunt. The reason is that there is a very unsure regulatory landscape out there, and they're concerned and we're concerned that, if we go on a plant-by-plant basis around the state, we would end up with a plant-by-plant approach to how to deal with once-through cooling, which might lead from total elimination in one region to total acceptance in another.

No matter what a Regional Board does, it's likely that they will basically build challenges on that. The idea of having 19 separate legal challenges with different decisions around the state is not appealing to us as agency, and so I've been tasked with trying to develop a statewide approach that would at least draw the buyers in one place.

To give you kind of an idea of where we are, the EPA has been trying for 30 years to put into place rules on once-through cooling power plants. They were able to adopt in 2001 Phase 1, what they called the Phase I Rule, which is for new plants. They also adopted in 2004 Phase II Rules for existing power plants. The Phase II Rule led to court action and appeals.

Eventually, it was taken up by the US Supreme Court to address some of those issues. And so back just this a year, a month ago or so, the US Supreme Court put out their decision on the Phase II Rule, and essentially kicked it back saying that EPA did have the authority to use cost in analyzing best available technology but didn't require it. Okay. That's not a very definitive situation for us, I'll have to admit, but that's where we are.

So what has the State Board been doing in this? Well, in the last few years, the State Board has been developing statewide policy to look at how to address the impacts from once-through cooling.

They had their first in September of 2005, their first scoping meeting on this almost four years ago. They released an early document in 2006, and then the RiverKeeper II Court of Appeals decision came out, and we stepped back and said we need to look at this a little bit differently. We revised the scoping document and in March of 2008, and we came out with a revised scoping document.

That scoping document essentially laid out a two-track approach to addressing the impacts of once-through cooling. It said on track one we would be looking at wet recycled cooling or its equivalent or dry cooling as one alternative. And then track two was, if that wasn't feasible either technically or economically, then we would go to track two, which was you had to mitigate those impacts through either new management practices, new intake structures, and new approaches to reach 90 percent of what you would expect to see if you had switched to Phase II -- to recycled cooling.

As you might imagine, we received quite a bit of concern on that proposal. And we had laid out in there a time schedule that looked at 2015 for low capacity, less than 20 percent capacity plants, 2018 for high capacity plants, and 2021 for the nuclear plants to come into compliance.

After that was out for comment, we received concern from your agencies, from CA ISO, from many of the generators that this would cause problems with grid reliability. We got together. We said, well, that's not really our area of expertise, so how are we going to address that?

And the approach that was decided is that we would step back and put together a working group. The working group was made up of members of my staff, myself, the Energy Commission, the Public Utilities Commission, the Independent System Operator, and the Coastal Commission, State Lands, and Air Resources Board. And the charge of this group was to look at how do we implement this approach of the two tracks of meeting the impacts associated with once-through cooling without -- with having a minimal disruption to the grid.

I know that you're going to have more on this from Mike Jaske, but I'd like to say that this has been a fabulous opportunity to work with the difference state agencies and sit down and really talk about where our concerns are, where our authorities are, and how we can jointly come together with an approach.

Right now, we are putting together the final -- Let me get to the next steps. We're putting together the final approach to our proposed rule making. We expect to have that it says up here at the end of summer. I didn't catch that when I was reading it. We expect to have that by the end of June, early July timeframe, and we would have it out public comment at that time with a workshop sometime in August, and hopefully a hearing for adoption in the fall or near the end of the year.

We have received from the combination of the Energy Commission, the California Public Utilities Commission, the CA ISO a proposal on how to implement that. We are integrating that into our policy as we speak. I'm very hopeful that this new approach will allow us to meet our needs, which is to address the environmental impacts associated with once-through cooling and also meet our energy needs in the state.

And I'm going to be here for most of the day, and I'm happy to try and answer any questions that folks have. But I'd like to say as I end that, you know, most of the time we hear from stakeholders out there is that state agencies need to learn how to talk to each other and get out of their solace and work together.

And I know we started out with the approach that, you know, hey, the water is what we worry about and that's what we'll deal with. You guys deal with the energy side of the house. But this working group has actually come together and looked at things from multiple perspectives, and I think that's what good government is about and we should be encouraging it. Thank you very much.

COMMISSIONER BYRON: Mr. Bishop, thank you. I know that you're going to be here. We've got a couple of panels that will have an opportunity to ask you a bunch of questions. I just want to check if there are any clarifying questions that you needed as a result. I got one for you if I may.

MR. BISHOP: Sure.

COMMISSIONER BYRON: You had indicated that the Regional Boards are obviously very keen on getting some direction here. Are they going to be bound by the decision of the State Board?

MR. BISHOP: Yes. The easy answer is yes. The way that the State and Regional Boards work is that the Regional Boards are what we call semiautonomous. They have their own board that's appointed by the Governor. They make the initial rulings on permits and enforcement actions and planning documents.

They are -- When they make those permit decisions, they have to look to a number of documents, and one of them is any statewide policy that has been adopted. If they miss it either by design or mistake, the State Board then has the opportunity either through a petition or through its own motion review to correct that issue. So when the State Board adopts a policy, then the Regions are required to implement it.

COMMISSIONER BYRON: Thank you. And you've given some indication as to the level of effort that's gone on since June of last year amongst the agencies and your board. And I think we'll be demonstrating that more in some of these panels, I think the next panel in particular, and that's, of course, one of the key purposes of this workshop is get that out there for public comment.

Mr. Bishop, thank you for being there and for being here today. Let's go ahead and keep moving because I want to make sure we get through these two panels but still have a lunch hour.

MR. BISHOP: Okay.

COMMISSIONER BYRON: Thank you.

MR. BISHOP: Thank you.

COMMISSIONER BYRON: Oh, and thank you for your animation. I don't think we've ever had starfish, and trout and goldfish animated on our screens before.

MS. KOROSEC: All right. Now we'll hear from Dr. Jaske, from the CEC staff.

DR. JASKE: Good morning. I'm Mike Jaske from the Energy Commission staff and currently in the Electricity Supply Analysis Division.

And oral presentations that you'll get in this session are from persons who have been active in the interagency working group that Mr. Bishop has talked about and in numerous other discussions among the three energy agencies.

So I think this slide duplicates what has been said before, and let me just emphasize that we're not here today to debate whether or not the Water Board should implement any particular OTC policy. We're here to figure out, given the OTC policy, what consequences would that have for reliability and how we dovetail those two concerns in such a way that there aren't reliability issues.

So as Mr. Bishop said, there were numerous comments received to their scoping document at comment point when those were due in May '08. The Water Board in the scoping document had actually suggested that there will be a statewide taskforce formed, and as it was described there, it was composed of largely the same body of entities that he just ran through earlier, but it wouldn't come into being until after the policy was enacted. And it would serve essentially as a review on the compliance plans that the scoping document envisioned at that point.

There were a number of entities that submitted comments that essentially said when you draw upon the expertise of these other agencies while you're developing the final version of the rule, and so Water Board staff formed this multiagency-working group, as Mr. Bishop said, and in particular the Energy Commission, PUC and ISO have been very active since then.

So again, I guess I'm repeating part of what Mr. Bishop said. Their preliminary policy of March '08 established what cooling tower as sort of the benchmark. Energy Commission staff and I believe our colleagues at the other energy agencies believe that the installation of wet cooling towers is most likely not going to be cost effective for these older plants. Most of these plants that we're talking about, you know, were constructed as far back as the '50s in some instances, and all up and through the '70s, and there are a couple, of course, that are newer than that represent particular challenges.

So our current belief is that most of these plants are going to either retire outright or wish to repower rather than refit cooling technologies into the existing power generation equipment. That presumption, of course, is part of what this workshop is all about to see, in particular from the generator community, whether that presumption is accurate or not, and I'm looking forward to that session later today.

So in the context of the belief that retirement or repowering is likely to be the consequence, then we need to think about reliability in terms of assuring that replacement infrastructure is, in fact, developed and operational in such a way that it dovetails with the point at which one of these OTC plants does, in fact, retire.

And what is the word; I use the word sufficient OTC capacity remains online. What does sufficient mean? It means at least two things, that we have enough total resources to meet the system requirements, but that we also have resources in particular local areas so that local capacity requirements are satisfied.

As it turns out, it is actually a very key dimension of this whole puzzle. Most of these plants are, in fact, located in local capacity areas, and we have to look at a bit of a tight scheduling process to ensure that new infrastructure whether generation or transmission is brought online and then an OTC facility could retire. In addition to just raw capacity, make sure the mix of both these existing resources and any new ones that are developed actually also satisfies the operational flexibility of the ISO needs in order to actually manage the grid effectively.

So generally the energy agencies, and by that term I include the ISO and then for the purposes of referring to Energy Commission, PUC and ISO altogether, we want to be sure to tighten up our analytic planning and permitting coordination in such a way that we can have realistic expectations about what is the reasonable options for these facilities in terms of replacement infrastructure, get those options into our planning processes, get decisions made, get permits issued, and do that in sufficiently timely way that is reasonable from compliance with ABC mitigation.

We're not at this point proposing any grand new process in which all that happens but to tighten up the linkages between our various analytic planning and permitting processes. And, of course, we'll be doing this in the context not just of dealing with OTC but with all the other resource policies that the state has, the constraints, the environment licensing presents either for generation or for transmission, and we need also to be doing this in the context of where the system is going to go over time for GHG reduction.

As Mr. Bishop said, there's been active involvement of the energy agency staff in the Water Board's working group since last June. We've had intensive discussions among the energy agency technical staff since about September when after several months of sort of getting comfortable with each other, as Mr. Bishop said, I'd like for you to bring forward an actual proposal. We turned up the effort level at that point and have had a very intensive discussion since then.

We have put forward the sketch of a proposed approach to the Water Board staff. It has been reviewed by the managements of the various agencies. We've received some feedback from the Water Board staff about that, which we are taking to heart and are adapting our initial proposal and submitting that back to the Water Board staff.

As Mr. Bishop said, he expects to incorporate this proposal into their policy, and we expect him to do the same, so we think we're on the same wavelength about our solution to reconciling OTC mitigation and reliability. And you will see the proof of that in the course of the next six or eight weeks.

So generally what is involved in this? We are looking at the tradeoffs between generation and non-generation options to replace the various OTC facilities. There are some local capacity areas where there is an existing surplus, but most of them are pretty tight, so generally speaking, there's a pretty tight linkage between no longer needing an existing OTC facility and bringing new infrastructure into the picture.

In some instances, there is a pretty clear known path by which that happens. The options in the specific facilities are already well identified. A sort of trivial example of this is the Humboldt plant. The Energy Commission licensed a replacement of the Humboldt facility and it's actually under construction. As soon as that facility is complete, then the old can be removed.

Something not quite as tight as that but very close to it, in the context of the South Bay facilities down in San Diego, it's well understood that with construction of the Otay Mesa Power Plant and the operational status of the Sunrise transmission line that Sunrise capacity will no longer be needed, and if its owner should then wish to retire it, it would not be necessary for reliability purposes.

For other facilities, there's more complicated situations not nearly as well lined out replacement infrastructure already in the pipeline, so that leads to further analysis to identify the options and understand the relative merits of each of the options, the timeline associated with those options, and then pursuing one or more of those options through processes at the PUC in procurement or transmission being one of those options first at ISO and then again back to the PUC if it's a significant enough facility.

Some of these options may come through the Energy Commission through its generation licensing process. Some may have, in fact, already come through our process, and merely be awaiting a long-run contract to convert themselves into a real live project.

There are particular issues associated with South Coast and for tradeoffs between the desire to replace a lot of OTC capacity and the necessity of air credits to satisfy South Coast's criteria pollutant licensing processes. And then a particular additional issue for LADWP, which is not, of course, jurisdictional to either the PUC or the ISO and yet is within the South Coast's airshed, so the Energy Commission staff is putting particular focus on these South Coast's LADWP dimensions of the issues.

So what comes next? Today's workshop is receiving inputs from stakeholders that either validate or refute, you know, various assumptions that we have been making, so we're extremely interested in the input from the stakeholders. We'll take that into account and finalize our input to the Water Board.

As Mr. Bishop said, they plan on publishing their proposed policy toward the end of June. Should that be the case, then the current plan is to conduct another workshop on July 9th under the auspices of the '09 IEPR to go through the details of this electricity infrastructure proposal. Clearly, they'll be included within the Water Board's own policy paper and substitute environment document, but probably not at the level of detail that the people in this room are interested in, so by offering to conduct another workshop under the auspices of the IEPR, we can get more detail and subject that proposal -- that part of their proposal to more scrutiny.

And that concludes my presentation. Are there any questions from the Dais?

COMMISSIONER BYRON: No. Thank you, Dr. Jaske. We'll press on so we can get any further discussion.

DR. JASKE: Thank you.

COMMISSIONER BYRON: Mr. Vidaver I think is next with just the facts. You have the longest presentation I think, David, but I'm sure it will go the fastest.

MR. VIDAVER: Fasten your seatbelts. I was given an outline a lot longer than the time I was allotted about a month ago. So the purpose of my presentation -- I'm David Vidaver. I'm with the Electricity Analysis Office for the Commission. The purpose of my presentation is to provide some consequence to the discussions that follow by illustrating the magnitude of the role that OTC has played on meeting California's capacity and energy needs.

I'm going to present quite a bit of data. I'm going to go through much of it very, very quickly. It will be published in a staff white paper coming out in 30 to 45 days or so. And the interim if you really want to burden myself or my staff, you can contact me and ask that the data be sent to you.

What we're talking, as Mr. Bishop mentioned, 19 facilities totally over 20,000 megawatts, 17 gas-fired and two nuclear. Almost all of these gas-fired facilities are quite old, 1978 or earlier. The exceptions being the two new units in Moss Landing and the Haynes and Harbor combined cycles owned and operated by LADWP. There's 13 merchant plants, 6 utility facilities, the 3 LADWP facilities, Humboldt Bay, which as Dr. Jaske mentioned, is about to disappear, and the 2 nuclear facilities.

OTC plants constitute 35 percent of the capacity and service of state loads and provide 19 percent of the energy, the gas units 27 percent of the capacity and 8 percent of the energy, and the aging gas units 23 percent of the capacity and 5 percent of the energy. And it's these aging gas units that will be the focus of this presentation.

As the numbers indicate, we're dealing largely with low capacity factor units whose value lies not in they're being an economic source of energy but a necessary source of capacity. We do have four new or newer or retooled facilities in Moss Landing and Haynes combined cycles that I alluded to, and the Harbor Facility and the Huntington Beach 3 and 4, which were retooled existing units. As a colleague of mine said, if you take a 25-year-old car, no matter how much you overhaul it, you still have a 25-year-old car. That was his description of Huntington Beach 3 and 4. My apologies to the owner.

MR. JASKE: But the owner agreed.

MR. VIDAVER: The energy from aging gas-fired OTC plants has fallen by it looks to be about 60 percent over the last six years. The energy from the Haynes and Huntington Beach combined cycles has obviously increased. The energy from aging OTC gas-fired plants has stabilized over about the last four years, and we surmised that absent the construction of new capacity in local reliability areas that amount of energy isn't to fall anytime soon.

These plants are needed largely during the summer. The energy from these plants, pardon me, is needed largely during the summer. AS you can see, that during non-summer periods it's needed as well in part because a large share of these facilities are in local reliability areas. Here are the 2008 capacity factors for these plants in descending order. I'm going to go through really quickly. The first here are nuclear units. The next two are the new combined cycles, Humboldt and Potrero, that have higher capacity factors than all the other aging facilities. And then we have everything else and we're going to discuss. Well, we're not going to discuss the nuclear units. We're going to get right to the new combined cycles.

It's really tough to illustrate how a plant operates both over the course of a year and the course of a day in single graph, so this is sort of what you're stuck with. This is the hourly generation of the Haynes combined cycle last year. You can see it ramped between 350 and about 550 megawatts on a continuous basis. The aspects of this graph that you should note are the density of the data points up at 550. That indicates that it's not a lot of hours at full output. You see some density at 350, so it spent quite a few hours down there. And you see nothing along the horizontal axis, so this plant was not shut off at night.

That's what its low duration curve looks like if you're more familiar with this. You can see that it spent about half of the year at 500 megawatts or above. It had set points of 350. It was off about ten percent of the time and that was, as the previous graph showed, in December. While we're talking about new combined cycles --

COMMISSIONER BYRON: And if I may, Mr. Vidaver?

MR. VIDAVER: Yes, Sir.

COMMISSIONER BYRON: Can we assume then when it's operating that it's pretty much at full capacity in terms of its cooling?

MR. VIDAVER: I'm not the person to talk to about the relationship between water consumption and output.

COMMISSIONER BYRON: Okay.

MR. VIDAVER: I guess you have someone else far more qualified than I am to do that.

This is one of the combined cycles at Moss Landing. You can see it operated in a similar fashion to the combines cycle at Haynes. The difference being that the Moss Landing combined cycle was shut off on occasion. You'll see quite a number of data point down along the horizontal axis.

Just to knock off the last new unit. This is the Harbor combined cycle cobbled together in 1984 by LADWP. You can see that the department relies on it for energy during very brief periods over the course of a year. The density of the points at full output indicates that it was ramped up to full load and left there, and the low duration occurred accordingly and it looks like this.

So now that we've dismissed all the new units, let's start talking about local reliability. Sixteen of the nineteen facilities are in one of the five ISO defined transmission constrained areas, the local reliability areas, or the LADWP control area, which is effectively an local reliability area due to local operating requirements for the LADWP plants.

North to South, we have the Humboldt LRA, the Greater Bay Area local reliability area, the Big Creek Ventura local reliability area, the smaller circle showing Los Angeles, which comprises both the LA Basin local reliability areas defined by the ISO, and the LADWP control area, and finally we have San Diego. If you're not in a local reliability area and you're an aging plant, and there are exactly two facilities, which meet that description, you could not run very much. This is the output of Morro Bay 3 and Morro Bay 4 that shows the similar operating profile. This is Moss Landing 6. Moss Landing 7 shows the similar operating profile.

Potrero 3 is in the San Francisco subarea of the Greater Bay Area Local Reliability Area. It is the one unit in the Bay Area that runs a lot. The capacity requirements of San Francisco proper require that Potrero 3 be on virtually around the clock. Because of its slow start nature, it can't provide capacity in the middle of the day without -- It can't provide capacity at all without operating, and it can't provide capacity during the day without being left on overnight due to its slow start nature. So of all the OTC units of the Greater San Francisco Bay Area, Potrero 3 in the one that produces a lot of energy in order to meet local reliability needs. In contrast -- In contrast, the two units at Pittsburg and the two units of Contra Costa produce very little energy. This is the chart for Pittsburgh 5, Pittsburgh 6, Contra Costa 6, and Contra Costa 7. All look very similar.

Now before we go on to dash through Los Angeles and San Diego, we need to talk a bit resource adequacy. As Dr. Jaske alluded to in his presentation, systemwide zonal and local capacity and stability requirements have to be satisfied, so we need quite a bit of capacity to meet these requirements in the local reliability areas. And as Potrero 3 indicated, the slow start nature of the aging OTC units requires that they be operated at minimum load levels to meet the spend and reserve requirements later in the day. Some are used year round and others primarily in the summer when loads are higher.

Now left to their own devices and to participate in the energy market, these units would not be profitable, and as California doesn’t have a long-term, (inaudible) capacity market, resource adequacy requirements imposed by the PUC on load-serving entities in the ISO control area lead to contractual agreements between either the load-serving entity or the ISO and the generator, which allow the generator to meet going forward with capital costs. The generators may agree or disagree with that characterization.

But most of these aging units have RA requirements -- excuse me, RA contracts, which are contracts between a load-serving entity and the generator requiring that the generator respond to ISO orders to dispatch in order to maintain local reliability. These contracts can be with one of the investor-owned utilities, it can be with the energy service provider, or it could even be with a public utility in the ISO control area.

For example, El Segundo has a contract with the City of Anaheim.

In the event that the utilities cannot reach agreements with a sufficient amount of capacity for RA purposes, the ISO can enter into RMR contracts directly with generator of up to one in duration, which requires that the generator respond to ISO request to dispatch. Of course, it’s always possible that a unit could be efficient enough so that a generator would want the right to dispatch it as part of its own portfolio. And then we have four units under a legacy DWR contract that Southern California Edison is administering in the Los Angeles Basin.

So with that being said, here’s an example of how much capacity is currently under contract. There’s about 38,700 megawatts of merchant OTC capacity, 11,200 or just over 80 percent of that is currently under contract of one form or another. And as you can see, that number declines over time and there is currently, to my knowledge, no plant that has a contract that extends beyond 2013.

I’m going to quickly run through the operating profiles. There’s a number of the Los Angeles and San Diego units. This is LADWP Scattergood 1 unit. You can see that it’s needed year round, and you can see that it runs almost entirely at minimum load. LADWP's need for the capacity of Scattergood is such that they have to have it available around the clock because the slow start nature requires that it be operating in the middle of the night to be available during the next day. That's what a low duration curve looks like for a unit that performs that service.

Scattergood 3 is needed during the summer, again the slow start nature. Encina 5 in the San Diego local reliability area has a very similar profile, as is South Bay 3. A plant with multiple units may operate one of those units in one fashion in order to meet local reliability and another unit in a completely different fashion. Encina 1 is very seldom needed in contrast to Encina 5.

Huntington Beach 1 apparently has two set points. Alamitos 3 runs on minimum load of about 25 megawatts. Alamitos 2 doesn't run at all. Redondo Beach 8 and all the Redondo Beach units run this rarely. Of course, that doesn't mean that Redondo Beach is any less necessary to meet local reliability needs than even the more frequently running that's in Alamitos.

One of the options -- Well, the options facing the OTC plants in the face of Water Board policy would be to refit with acceptable cooling technologies, to repower, or replace onsite, or to retire with any replacement capacity if it was necessary that they build in another location.

As Dr. Jaske said, staff has concluded that the cost of refitting or such that most merchant plants -- most if not all merchant plants or at least aging merchants plants there were required to refit would retire unless the costs were recovered somehow through long-term contract or some form of contract. There have been several studies done on the potential for refitting these plants and the cost of doing so. They're referred to here. At the bottom, you can see the URL at which you can locate these studies if you're interested, waterboard.ca.gov.

EPRI found retrofit costs between $17 and more than $675 million. The total cost of retrofitting all these facilities would be in the neighborhood of $4 billion. This least this is a very contentious number as the next slide will indicate. All parties generally agree that there are other penalties. The $4 billion is the capital costs. Refitting these plants would lower their heat rates, result in higher operation and maintenance costs, and lower their capacity I believe. EPRI concluded that if you refitted all of the plants that could be refit you'd lose about 400 megawatts in capacity.

EPRI found wet cooling that, while theoretically possible, is a high degree of difficulty. Tetra Tech found that, while wet cooling retrofits were technically feasible, that feasible facilities still faced hurdles. If you talk to the generators, as we will this afternoon, you might find that many of them disagree about the potential for refitting their facilities and the likely costs of doing so.

And finally, the nuclear plants are about 60 percent of the energy from OTC plants in total, so we can’t ignore them. They would be the most costly to retrofit. They would experience the most significant performance penalties, and as Mike alluded to earlier, some areas are harder to figure out from a planning perspective than others. The Los Angeles Basin is difficult to get a handle on in part because San Onofre plays such an important role both in the Basin and in Southern California in general.

The options for refitting, retrofitting, or retiring, and replacing once-through cooled plants in the Los Angeles Basin will likely depend on whether one assumes the presence or absence of San Onofre. And the ability to import power into energy into Southern California is in part a function of whether or not San

Onofre is there and operating, so that analysis is one of the more complicated facing the energy agencies.

COMMISSIONER BYRON: Any questions?

MR. VIDAVER: I believe that's it. If there are any questions?

COMMISSIONER BYRON: Mr. Vidaver, thank you. I think that, even though you've just presented facts and data, I suspect that your presentation will generate a lot of response on the part of the participants. Let's save those for the panel discussion.

MR. VIDAVER: Thank you.

COMMISSIONER BYRON: Thank you very much.

MS. KOROSEC: Next, we'll hear from Dennis Peters from CA ISO.

MR. PETERS: Good morning. My name is Dennis Peters with the ISO. I'm the External Affairs Manager. And my role here today in this presentation is to give you what the current and perspective role of OTC plants are in reliability.

COMMISSIONER BYRON: Good.

MR. PETERS: I can tell you it's significant. As Mr. Mansour indicated in his opening comments, it's not a compromise. In terms of my presentation of it, I'll just be speaking to those plans that are within the ISO balancing authority area. Those are 16 of the 19 plants that are affected by the policy, and I'll be speaking to system reliability, local reliability, and the importance of these plants in the integration of renewable resources.

So just to kind of set the stage for once-through cooling policy in terms of the ISO's objective, we need to maintain grid reliability in compliance with federal standards while meeting the state's environmental goals. And I apologize. I'll have to take a lesson in PowerPoint from Jonathon Bishop. I don't have the balls spinning in the air. But as you can see, not only is once-through cooling something we're trying to work with regard to reliability, we all know about the lack of air credits in South Coast Air Quality Management District and possibly other areas. There was is, you know, of course, the integration of 33 percent renewables, as well as the greenhouse gas AB32.

I was in a discussion with I'd say some veterans in the energy business recently, and they said, you know, trying to balance all these balls while maintaining reliability is like rocket science. And someone responded back, they said, no, it's actually more difficult than rocket science.

COMMISSIONER BYRON: Mr. Mansour, I note that the gentleman on the tight wire is well dressed and not unlike yourself.

MR. PETERS: So you've seen these maps before. I don't need to go through the details. You've seen them in the previous presentations, but you know once-through cooling cool generation represents a significant amount of in-state generation. As for the ISO balancing authority area, it represents 38 percent of the installed generation capacity. That's a significant amount. And, of course, the other three plants are in LADWP balancing authority area.

I'll be going through each of these, the next bullet items, in more detail, but it's needed for meeting system demand, as David Vidaver had mentioned in his presentation, essentially resource adequacy and that's supply to meet demand that's needed for local reliability. That's in reference to local capacity reliability areas. I'll get into some detail on that. And thirdly, it's essential to the renewable integration or the use of procurement of ancillary services for ramping capability, regulation, and load following.

This graphic here I'll spend just a little bit of time explaining it. As you can see in the title, nonnuclear, this is excluding the nuclear, but it's nonnuclear, once-through cooling plants contributed greater than 25 percent of supply to meet our 2008 peak demand, and this is similar for years going back as well.

If you work your way down from the top, at the very top, these are once-through cooling units with less than 20 percent capacity factor. Next down is once-through cooling plants with greater than 20 percent capacity factor. And you can see a significant amount in the highest peak load hours in 2008 those units were required, so if there's any perception that low capacity factor plants are not important to the reliability and to keeping the lights on, this graphic will show you that they are. They absolutely are. You know this is the total -- The graphic kind of gives you the entire supply picture to meet demand in those hours, and as I said says 25 percent comes from the once-through cooling plants needed to meet system demands.

COMMISSIONER BYRON: Mr. Peters, so the x-axis on the curve there, that's just the -- those are in rank order and it would just be the first 30 or so either, what, hours or days or?

MR. PETERS: Those are hours where peak -- where the demand was within 93 percent of peak demand.

COMMISSIONER BYRON: So your highest --

MR. PETERS: Highest hours.

COMMISSIONER BYRON: -- 30 hours in the year?

MR. PETERS: Yes, correct.

COMMISSIONER BYRON: Thank you.

MR. PETERS: Okay. I'd like to spend a little bit of time with this slide here. You know, David Vidaver went through some of the, you know, issues of local capacity requirements. I'll get to that $5 billion number in a minute that's in the top of the slide. But I'd like to just kind of explain a little bit about local capacity requirements. It's really subset of overall resource adequacy, and it represents the capacity that needs to be procured in specific local areas. It represents the minimum resource capacity needed, and I'll emphasize this, that were available, you know, in a local area to safely operate the grid, and it's sort of a load pocket concept.

And you know, we mentioned we have ten local reliability areas in the ISO's balancing authority area. The once-through cooling resources that are in five of the local capacity reliability areas represents an average of 58 percent of the capacity in each of those areas. And that averages in those five areas anywhere from 46 to 61 percent. And David had already gone through which five those are, so I won't repeat those.

So basically, it's a load pocket concept. Load in a certain area may exceed the maximum transmission capacity available to deliver resources into that area. And when we do these studies, we do this every year, and it's in addition to our transmission planning process, we have several criteria to follow. We have national reliability criteria through the North American Electric Reliability Council, and through our Regional Western Electricity Board Meeting Council planning criteria, as well as what's MORC, or Minimum Operating Reliability Criteria.

And so you can see this is a significant impact if these plants were to retire and not be replaced or retrofitted. It's a significant impact to reliability. What we did last fall was take a look at what would be the cost to replace, and that's sort of my item on the top there. What would it take if we were to shutdown the nonnuclear once-through cooling plants, and we actually included in this study given that Humboldt was being replaced right now, and I think we even included El Segundo before the priority reserve issue came up down there. But just to replace those plants if they were to retire so, of course, this is a worst-case scenario, would require $5 billion in high-level transmission upgrades. These are 500 kV lines as well as local transmission upgrades in each of the local capacity reliability areas.

What's not in that number is the replacement power that would be needed at the other end of that line. So if you build a transmission line into, you know, the LA Basin, you need something on the other end of that. Not only do you need to replace some power on the other end of that, you also need things, you know, like static VAR comps there to support voltage within the LA Basin.

That aside, the cost of, you know, transmission and the cost of replacement power is a lengthy process to approve transmission, and as you could imagine, given that most of these plants are in the LA Basin, it would be very difficult and a very lengthy process to build that transmission and get it permitted.

Sort of the last role in reliability that I want to touch on was the role of the once-through cooling plants, particularly the nonnuclear units because the nuclear units are used for base load generation. As you can see in David’s graph, they run from, you know, 80 to 90 percent capacity factors of the base loaded plants. Last fall the ISO released our Integration of Renewables Report. We identified the need ancillary services including regulation and inter-hour load following to meet the 20 percent. That was just to meet the 20 percent Renewable Portfolio Standard. And we determined, yes, there was enough capacity there to provide those services. And as I said, it’s the nonnuclear OTC plants that provide the services.

Replacement generation, this is a really key point, any replacement generation needs to have similar operating characteristics. They have to have the capability to have low minimum load, have the ability to ramp up very quickly, and to be able to ramp the different operating points.

Right now, we're engaged in a study to see what we would need to support the integration of 33 percent Renewable Portfolio Standard. I think it's probably just clear, I don't even have to say this, but you know more fossil-fired generation will be needed to provide the ancillary services we need to support 33 percent integration, you know. And many have said, well, once, you know, the once-through cooling plant goes away, it's replaced by the renewables coming in. Well, no, it not.

We all know as most of us know in this room in the business that renewables are intermittent. The wind tends to blow at night. We tend to see maybe two the three percent of winds supporting our peak load. We have significant ramps in the morning when the wind comes off and the load is coming up. The sun doesn't always shine and it doesn't shine at night, so these plants are critical to renewables integration.

So some considerations moving forward, retrofitting, repowering, otherwise, replacing some existing plants in the same areas. I guess commonsense would just tell you that, you know, the best solution is repowering or retrofit at the existing site. These are located in, like I say, five of them are -- or sixteen of them are located in local reliability areas. Brownfield sites are obviously the best option.

But we also need to identify transmission upgrades. As we move forward if plants repower, then we're going to have to identify the transmission upgrades as needed to maintain grid reliability. There's definitely going to need to be coordination on the nuclear, you know, plants with the Nuclear Regulatory Commission oversight of the cooling retrofits.

And finally, as I kind of end where I started, this is truly a balancing act coordinating once-through cooling implementation with other environmental initiatives, greenhouse gas, renewable integration, the issue of acquiring air credits. These are all issues that make this an even more complex issue for us to maintain grid reliability. That's all I have. Thank you.

COMMISSIONER BYRON: Thank you, Mr. Peters. I don't think we have any more questions. We'll press on with our last presentation. Thank you.

MR. PETERS: Thank you.

MS. KOROSEC: Next, we'll here from Robert Strauss from the PUC.

MR. STRAUSS: Good morning. I’m Robert Strauss from the PUC. The PUC regulates the independently owned utilities. They do not have the ability to build new power plants by itself. We don’t built power plants. We don’t retire power plants. We can’t force the retirement of a power plant. Our main --

COMMISSIONER BYRON: Mr. Strauss, I think we’ll just -- we’ll just correct that just because I don’t think you meant you regulate the independents. You regulate the investor-owned utilities.

MR. STRAUSS: Correct, the investor-owned utilities.

COMMISSIONER BYRON: Yes. Thank you.

MR. STRAUSS: And the three major investor-owned utilities Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric represent approximately 80 percent of the load-serving entities and provide for about 80 percent of the power in California, so they’re a major power.

So the PUC has been -- The IEPRs in the past have instructed or encouraged the PUC to replace the aging power plants, which include the large owned OTC plants, as David Vidaver spoke earlier. The PUC has been working for that, and three of the projects that have been mentioned are now under construction are the Humboldt, the PG and E project, the Potrero, which is the transmission solution, and the South Bay Power, which is both transmission and a generation solution. The PUC wasn't the sole person these plants were involved with, ISO analysis, there was utility analysis, and participation. There's a lot of work that went on by a lot of entities.

But the PUC's main activity here, I mean, in the OTC has three basic functions. One is resource adequacy program, the second is approval of transmission projects, and the third is the procurement. So I'm going to be speaking mainly about procurement today.

The PUC has approved projects in the last couple of years for replacement of power plants in some local areas that would reduce the need for some of the current OTC plants. David Vidaver had a chart showing the contracts for OTC plants and how they decline very steeply over the next three years. Well, there's not going to be new power plants built in the next few years to replace those plants, so those plants are going to need to be re-contracted for some period until replacement power can be built.

MR. MANSOUR: Just again, some clarification. Go back to the last slide. Which of the projects are you saying that are under construction than Potrero's OTC?

MR. STRAUSS: Well, it's the Trans Bay Cable.

COMMISSIONER BYRON: Just transmission.

MR. MANSOUR: But that is just one unit of Potrero. That's unit three.

MR. STRAUSS: Right. It's the OTC --

MR. MANSOUR: There is no project for --

MR. STRAUSS: It will eliminate the use OTC at Potrero.

MR. MANSOUR: Okay.

MR. STRAUSS: The other units at Potrero do not use OTC.

MR. MANSOUR: Not end the use. You're saying end the use of what you see at Potrero. That is not correct. That's correct?

MR. STRAUSS: No. It will end the OTC at Potrero because the intent is to close Potrero 3, which is only unit at Potrero that currently uses OTC. The other units are all air-cooled.

MR. MANSOUR: Okay.

MR. STRAUSS: The PUC has stated its desire in its long-term procurement plan decisions to reduce OTC, but the main thing is the cost involved and system reliability, so we're trying to balance the environmental goals with the system reliability and cost. As you heard earlier, the cost of replacing these plants is significant. If you closed all these plants and stop contracting with them immediately, there would not be sufficiently reliability to run the system, so it's a balance to try to make it work. We've been working cooperatively with ISO and the CEC and the Water Board to try to make this whole thing work well.

The PUC procurement process is basically to analyze the resource needs and priorities. That includes input from the CEC and the ISO for the reliability transmission needs coming forward. The utilities file the long-term procurement plans. They go through a very involved regulatory process. Eventually, the Commission approves that and approves a residual need. The utilities then go out to a competitive process to be able to meet that need, and the Commission reviews contracts and hopefully approves those.

In that analysis process, the loading order, which is the energy efficiency, demand response, and renewables, and distributed generation are the priority. That's one of the main lead priorities in going forward with the long-term procurement process along with the market.

Now the long-term procurement process takes into account the state priorities, OTC, the preferred resources, resource adequacy to calculate what we call residual need. It's the amount of fossil that's needed.

It's residual because the priority is with the preferred resources, so the residual need of the fossil is what needs to be built of fossil resources to keep the system running and ensure reliability and to do that at the lowest reasonable cost.

The utilities take an authorization to build -- the residual need to build new generation. They go through a procurement process that has a lot of regulatory review process, a lot of oversight to ensure that it's a fair and competitive nature. The main key here is that these OTC plants are in a very good location. They're needed for local reliability, but there are other options. We want to go to the market to decide what are the best options. Is repowering a plant the best option? Is building a new plant the best option? Through a competitor process, we can help determine that and what the market decides.

The RFO contracts finance the building of new power plants. I said we don't have the ability to permit a new power plant, but by having utility rate payers fund the contract or the Commission approves a contract for buying power from a power plant that will provide the basis for a finding so that a new power plant can be built or an existing one repowered. And it talked about the two different types, the short-term ones, which would be with existing plants to give them the financing to keep operating until replacement power can be in place, and then long-term ones to build new power plants and to obviate the need for using once-through cooling. The RFO process takes six to the eighteen months, but there's a lot of variables that are involved in that and it takes a long period of time.

In the December 2007 decision that authorized PG and E to go out and build over 1,000 megawatts of new power plants, they went forward and issued an RFO. They signed one contract, which they filed an application for approval before the Commission in March. They've got other contracts coming on that, but you can see the duration of that process of going through the complexity of trying to select the right contract, the right resources that will meet the needs of the area.

Once a contract is signed, it goes through a PUC approval process. The utilities file an application and parties intervene. That can take six months to twelve months depending on the complexity of the process and whether hearings are needed, and that's basically it. Any questions?

COMMISSIONER BYRON: No. Thank you very much, Mr. Strauss. Let's go ahead and move to our panel. I guess it's actually made up of some different folks.

Maybe we should stop for a moment and see if there's any questions, brief questions, clarify, or whatever from any members of the audience that would care to ask. I know I may be jeopardizing our schedule, but I think there was a lot of material that just went through. Again, if you could just limit yourselves to clarifying questions if you need any.

MS. KOROSEC: If you do have questions, come up to the podium in the center, please.

COMMISSIONER BYRON: Right. All right.

MS. KOROSEC: There's none online. Does anybody have some questions? No. We've had none.

COMMISSIONER BYRON: Okay. We'll proceed.

MS. KOROSEC: All right. So will the panelists for panel one please come up to the front table?

COMMISSIONER BYRON: I'm sorry, Mr. Jaske -- Dr. Jaske.

DR. JASKE: So the agenda for the remainder of today's workshop will have panels composed of various similar -- close to similar backgrounds. So this first panel is the environment agencies, and you've already heard from Mr. Bishop. We also have Mohsen Nazemi from South Coast AQMD, Mike Tollstrup from State Air Resources Board, and Al Wanger from the Coastal Commission.

And in order to sort of make sure everyone fully understands the issues behind what these various entities have as their responsibilities and what their situations are, unlike the panels this afternoon, we gave this group an opportunity to make sort of some opening statement about the nature of their organization or the issues in front of them. And Mr. Nazemi did ask to make such a presentation, so before we get to the questions, Mohsen, if you could run through your brief presentation. Give us some common background.

MR. NAZEMI: Good morning. My name is Mohsen Nazemi. I'm Deputy Executive Officer for South Coast Air Quality Management District. And I appreciate the invitation by Dr. Jaske and also the opportunity to give a very brief overview. I think you already this morning a number of references to potential problems and offsets in South Coast Air Quality Management District. Our agency is a regional local air pollution control agency, which governs over all of Orange County and the non-desert portions of Los Angeles, San Bernardino, and Riverside Counties with a population of 16 million, almost half of the state and unfortunately the worst air quality in the nation.

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COMMISSIONER BYRON: Sorry, Mr. Jaske, Doctor Jaske.

MR. JASKE: So the agenda for the remainder of this workshop, we'll have panels including various similar, folks with similar backgrounds so this first panel is environmental agencies and we've already heard from Mr. Bishop. We also have Mohsen Nazemi from South Coast AQMD, Mike Tollstrup from State Air Resources Board, and Al Wanger from the Coastal Commission. And in order to make sure everyone fully understands the issues behind what these various entities have as their responsibilities and what their situations are, unlike the panels this afternoon, we gave this group an opportunity to make sort of some opening statement about the nature of their organization or the issues in front of them and Mr. Nazemi did ask to make such a presentation. So, before we get to the questions, Mohsen, if you could run through your brief presentation, give us some common background.

MR. NAZEMI: Good morning. My name is Mohsen Nazemi and I'm Deputy Executive Officer for South Coast Air Quality Management District. And I appreciate the invitation by Dr. Jaske and also the opportunity to give a very brief overview. I think you already heard this morning a number of references to potential problems in offsets in South Coast Air Quality Management District. Our agency is a regional/local air pollution agency which governs over all over Orange County and non-desert portions of Los Angeles, San Bernardino, Riverside County, population of 16 million, almost half of the State and, unfortunately, the worst air quality in the nation.

One of the primary responsibilities we have is permitting of various stationary sources including power plants. And as part of permitting of power plants, one of the cornerstones of our regulations which is actually a federal/state law that we implement for regulations is called new source review or NSR. You've heard of other acronyms this morning. I'm going to add one more to it -- NSR.

NSR applies in offsets. Emission offsets are required whenever there are new facilities built or relocated or monitor stations of existing facilities. However, under our New Source Review program and, in particular, in relation to utility repowering we have, for decades, had exemptions in our program from offsets requirements whenever a power plant using needing to replace some of the old utility borders that gas turbines. We had exemptment (sic) done from requiring the offsets provided there is no increase in capacity.

However, in the early 2000, due to the California energy crisis and, later on, in the middle of 2000, based on projections, the Energy Commission made about shortfalls in summertime in Southern California. We also amended one of our other New Source Review rules referred to as priority reserve rule to allow power plants also to access our bank of credits for new power plants or for repowering where they're actually increasing their capacity as well as just replacing the units.

However, because these exemptions do not exist under federal and state law, our agency still has to provide these offsets and we use what we call our internal offset bank to provide the offsets for these types of projects. And, in order to do that, we have been, for two decades almost, running a new source review tracking system where, again, in early 2000 EPA asked us to adopt that into a regulation as well.

Once we did that, a number of environmental organizations, natural resources that has counsel, communities, better environment and others filed two lawsuits, one in August of 2007 challenging our amendments of our priority to reserve, Rule 1309.1, to allow power plants to access our bank of credits and also our new source review tracking rule, Rule 1315.

In July and November, again in 2008, Judge Ann Jones of the State Supreme Court ruled in favor of the environmental organizations invalidating both those rules due to CEQA issues. And in August of last year, another lawsuit was filed by the same group of organizations, environmental organizations and this one was a federal lawsuit challenging the validity of all of the offsets in the district's internal bank.

So, what happened, as a result of this court decisions, State court decision, we are not able to permit any projects that were relying on these internal banks, in particular, essential public services, other local government business projects and, in addition, no new or repowered power plants can be permitted using our internal bank.

The only remaining avenue left for these projects including the power plants to obtain permits is to provide their own emission reduction credits or ERCs where they can buy in the open market. So what's the problem with that?

The problem is that there's not enough ERCs in the open market and, in addition to that, they're not only expensive but they're essentially unaffordable. Now, without the ability to move forward some of these projects, as you've heard earlier, you have 8032 greenhouse gas reductions that use new renewable portfolio issues that will be delayed since these projects can't move forward. In addition, we have over 1300 permits pending that cover a variety of essential public service, local government and other businesses.

As a matter of just background, this is about a dozen or so projects that are pending. These are all power plants proposed in South Coast with the exception of the last two down in Antelope Valley and Mojave desert area. But all of these power plants were relying on being able to obtain credits from the district's internal bank and the first three projects listed above are actually obtained through power purchase agreement with Southern California Edison about 1900MW that cannot move forward at this point.

The next couple of projects are 1200MW. We actually denied those permits and they are undergoing CEC licensing process at this point and CEC is looking what to do with those two projects.

The remaining 2000MW are all pending. Just to give you an idea, you see a couple of municipality projects here. One Canyon Power Plant for the City of Anaheim, it's a small sized project, 200MW. They just ended up spending $16 million just buying emission reduction credits for a 200MW project. The City of

Riverside also has a 99MW project just find the ERC transfer for those. They accrued up to about $6 million just for emission reduction credits. So, you can see that this is very expensive and not potentially affordable.

Also, the two projects in the High Desert area, the Victorville and Palmdale, because of the scarcity of offsets in their district, they had also, under State law, they can request or we can approve, transfer our credits from our district to their district. And they wanted to transfer some credits to be able to permit or license their projects.

So, to give you an idea why there is a problem with credits, if you look at this bar chart, the white bar chart shows the availability of ERCs for the most (inaudible) particulars of PM10. And as you can see, between 2000 and 2008, the amount of credits available in the market dropped in almost half of what it existed eight years ago.

The blue bar chart, on the other hand, is the price of credits. And, as you can see, the price increased by almost fifty-fold and, in fact, this slide shows the highest price paid for PM10 in 2000 April is $247,000 per lb/day. In 2009, we actually have $320,000 per lb/day.

And, just to show you why there is a scarcity or there is a, trouble in South Coast, that mustard colored bar chart is beyond, is only the amount of credits we have by those three power plants in the previous slide that have obtained power purchase agreements with Southern California Edison. And only to provide credits for those, you can see it is more than twice the ERCs in the open market. So there doesn't even exist enough ERCs. And I had to find out that many of these ERCs are held by companies that don't fall under any of our exemptions. So they have plans for their own expansions in the future. So, even though they are valid ERCs, they are not willing to sell them at any cost because they have their own projects.

Doctor Jaske asked me to give you an indication so if there isn't enough ERCs in the open market, is there enough in the district's bank to cover that?

To give you an indication, our bank consists of credits that goes back to Pre-1990 and in our new source review tracking system, we have been reporting these credits to EPA on their Resources Board, like I said, for over almost two decades. And the number of credits that we have been reporting are shown in the first slide.

As a result of early 2000 requests by EPA to adopt our new source review tracking into a rule, we actually negotiated and discussed the validity of these credits and EPA wanted us not to use any of the credits that we no longer hold the records for. And, voluntarily, we agreed to do that. So you can see that we reused our bank account for PM10, in particular, by 92% percent in early 2000 when we discussed this with EPA.

And, as a result, I think today, if you look at what took place in early 2000 during the California energy crisis, almost 4900MW of new generation was built at that time. Unfortunately, or as a result, 3,000MW of old generation was taken out of service. But you can see that, at that time, before we introduced our bank, the amount of credits used by power plants was less than 2% percent of our bank. So it really had no effect on our bank.

But even today, if we look at all the pending projects within AQMD and the two projects outside the AQMD, Mojave and Antelope Valley, the amount of credits that's needed for these 4,000MW in South Coast and other 1100 outside, depending on which pollutant you look at, is anywhere from 1% percent to 14% percent of the bank.

Now, I do need to, again, remind you that there is a federal lawsuit pending that has not been ruled on by the federal judge that is questioning the validity of these credits. Now, these are important because as you heard this morning, once through cooling in South Coast is about a third of total gas power generation and many of those projects are either owned by other MWD, AS or NRG and overall, the gas power generation in South Coast, 50% percent of the plants are over 40 years old and not that it's old. I know many of us are over 40 years old but for a power plant, that's probably considered old.

So, this brings us close to where we're going with my last slide, where we're going from here. One of the things that we have done since the state court decision is we have appealed the state court decision primarily because the State judge ruled that not only we cannot use our bank of credits moving forward permitting any other projects but any permit that has been issued since we had adopted our Rule 1315 is also in jeopardy. And, so we appealed that decision to put a stay on over 2,000 projects, almost 3400 permits that have been issued between 2006 and 2008 when the judge made her decision.

We also initiated rule development to readopt our new source review tracking rule. Most of these appeals and re-adoption are not going to be quick. They're going to take about a year and there's no guarantee that once we re-adopt our rule, there is no further challenges. We have participated in mediation with the litigants and environmental organizations. So far, we have not come to any agreement under mediation.

And, lastly, we have proposed legislation under Senate Bill 696 which is sponsored by Senator Rodney Wright. What this legislation does is reinstates the amendments to Rule 1309.1 and 1315. It does require power plants -- and I know these are some of the questions that Doctor Jaske’s going to ask of the panel -- to meet very, very stringent standards beyond what’s typically required of power plants in order to be able to access the credits from our internal bank, requires power plants not to get those or doesn’t allow the power plants to get those credits for free like essential public services. They would have to pay a mitigation fee. However, our agency has committed -- and we have done this with the previous mitigation -- to reinvest these in emission reduction projects in their areas where these power plants are going to be built.

And, finally, as part of this legislation, because there was a significant concern from the environmental groups that they did not want Southern California with the worst air quality in the nation to be the mecca of all power plants to everybody comes there and builds, we have included in this proposed legislation the requirement for the Energy Commission to do a needs analysis to indicate whether or not that power plant is actually needed to be located in southwest area. And that concludes my presentation. Thanks for the opportunity.

COMMISSIONER BYRON: Thank you, Mr. Nazemi. The, I'm probably remiss. I probably should have introduce Arthur Jaske. I had asked him if he would moderate this panel, take us through a series of questions and I very much appreciate the panelists that have made an effort to be here today. We've got the right folks here, Mike, I think to help answer some of these questions.

MR. JASKE: As Commissioner Byron said, my role here is to work us through these questions and also end this some time so we can take lunch. At the expense of, there's follow-ups that occur to me so I'll pursue that. So, let's start with the very first question and this actually, the first (inaudible) of these are mostly oriented towards to the Water Board. So, Mr. Bishop, if you'll -- clearly, what the agencies are proposing implies that if you will to some degree or considerable degree of respect for, with its history of reliability. Does your agency think it has the discretion to encompass that in its proposal?

MR. BISHOP: Well, the short answer is yes. The longer answer is the Water Boards, in general, have the biggest area of flexibility in implementation. They're much more constrained on, in meeting a certain goal but once that goal is identified, we have, I think, a lot of flexibility in how we get that, to that goal. So, as I stated earlier as we talk along, as you were talking (inaudible), we're very open and hopeful in essentially incorporate a more flexible implementation schedule. It still needs (inaudible).

I will make one interdiction in this I always have to say which is that our Board deals very strongly in deadlines and so the need to have a milestone or accountable is very important to our Board and will have to be incorporated as we move forward.

MR. JASKE: I would like to ask you about one facet of milestones. Earlier today, in my own presentation, I indicated that because some projects, new infrastructure was, are you implying that would mean particular OTC plants that might no longer be needing to prove reliability sooner in time than others and that implies, in effect, a different compliance with a, for different group of plants or even as specific as individual plants. Is that kind of approach presenting the issues in developing your goal?

MR. BISHOP: You know, once again, the short answer is no. The longer answer is that we can identify different compliance dates for different plants or different groups of plants or even different units within a plant if we feel that's appropriate. We just have to justify that (inaudible).

MR. JASKE: Moving to question two, in reference to California Water Code in, among the things in the section of the Water Code that appears to, in some respects, provide or require for the balancing of considerations; is that the right to think about it and is reliability, you know, to be thought of in that sort of balance fact?

MR. BISHOP: Oh, we, as remotely many (inaudible) space, we have been working somewhat on legislative performance and (inaudible) certain times. We are, on one hand, required to minimize the impact of the power plants but we also are required to take into account the impacts of our rules on the California eco-society as a whole and, as such, we always are in that balancing mode.

We can't, on one hand, trade off one impact for the other and say we will not address this because it has other impacts. We have, what we've been charged to do is to figure out how to minimize the impacts in both ways. So, in terms of regional liability, we include and are now going to require, have large requirements need to bring stability in the grids. We are committed to that. We are moving on, going to move that forward. At the same time, we can't say because of impacts to the grid, we are not going to regulate once through cooling. So we have to walk that line between them. I feel we have the flexibility to do that, working on that front.

MR. JASKE: Would you be at all concerned if the US EPA were to resurrect its rule making activity and they have a different legislation requirement in that their, the flexibility that you're talking about a lot might not exist in the USEPA rule?

MR. BISHOP: I can't speak for the USEPA but my experience with their rule making is that they will have a, if their rule making results in less flexibility for us, we are likely to be found compliant. We can be more stringent than the EPA in most instances but not the last time. The air folks might have a little disagreement on that on some issues but for us, that's normally the case. My expectation is that it you would take the numerous (inaudible) quite a while to come up with a new approach and I wouldn't expect to see something out of that in a while.

MR. JASKE: We'll get to question three. I recall that your presentation this morning mentioned the Supreme Court decision of April 1st. It wasn't clear in your presentation whether you were, you mean that outcome as something that (inaudible) did or did not alter the trajectory of business the Water Board staff is on the issues that are involved.

MR. BISHOP: Well, that’s probably because I wasn’t clear on it. I wasn’t clear because it’s not a clear-cut direction what the latent -- my legal counsels advised me is that it’s such that the USEPA may take into account cost. So, we will likely mimic that in some way and try to develop a criteria for which that may be considered. We don’t expect to change or cause the wholesale to address it but we would expect to acknowledge that this report has said that that may be a factor in trying to lay out some criteria that a power plant could use or usually could use to make that argument. My expectation is that would be to a regional board with an appeal process (inaudible).

MR. JASKE: So, question four now, sir, to open things up potentially to the rest of the panel, so clearly, the Water Board’s general approach that we talked about this morning has reached through the lens of the energy agency’s interpretation of also new infrastructure is going to be necessary. You talked about that directly so, I guess, generally speaking, when new kinds of infrastructure generation or turning emission projects of sort of major size or perhaps or distributive generation that, you know, evolved outside of our jurisdiction but still require some sort of permit from the local agency. Do your agencies, you know, have any issues with the permitting process that is for all of this new infrastructure? Is there any way that you could build on your earlier approach?

MR. BISHOP: Sure, thank you. I think the reason that I wanted to give that earlier presentation was that for a simple answer to a question, I don’t have to speak on five minutes but, in general, I think you realize that our agency has looked at this issue awhile ago and, in fact, when we adopted new regulations to control air pollution or criteria of pollutants in our basin, that was when we started to consider that if old utility boilers which is less efficient, is dirtier and more polluting has to be replaced with a new, more efficient and less polluting cleaner technology that needs to become a facilitation under our regulations. So, we have, for decades have had this exemption under our rule to allow that to take place.

Furthermore, when we realize that a power plant may need to be located at a location different than where it used to be located, given some transmission restrictions, of course, in consideration to that, we began to look into amending our new source review further to allow those new power plants to be built. And, we do have, as we indicated, Arthur Jaske, regulatory authority over permitting of not only just central generation but also the distributed generation.

However, through our work with the Air Resources Board and their distributed generation and certification program, with the exception of very few technologies such as fuel cell and other micro-turbine technology, in general, distributed generation is dirtier compared to a central power plant because their inability to use the most sophisticated control technologies. And so, although you would be shredding the generation through a larger area but when you look at it per megawatt or per kilowatt of power generated, there's a greater amount of emissions or criteria with the smog forming compound in general.

So, even though we have the jurisdiction, we do look into tighter standards for distributive generation. But with the advent of the AB32, I think everybody looking at renewables such as biogas, landfill gas and other types of technologies as well. So, we are facilitating those but with the lawsuit and the court decision in front of us, we have a very difficult time moving those types of projects forward at this time.

MR. JASKE: This is a follow-up. In the normal course of business or distributed generation facilities that are, you know, smaller scale that would come to the Energy Commission, those facilities commonly require ERCs purchased from the market or do you have a program that allows them to use, you know, internal bank credits?

MR. BISHOP: What we allow under our resource review program is for small emitting facilities that have emissions of less than 4 tons per year, we provide them an exemption from requirements of providing offsets. However, our internal bank then is used to cover the offsets from those projects. You may recall Southern California is including four 49MW units in Southland a couple of years ago and those were all utilized those exemptions. So they didn’t need to provide ERC but yet, we provided those ERCs from our internal bank.

I guess, the big difference is that with the larger power plants where we allow them to access our bank even though they’re under 4 tons, what happens is we still provide the credits from our bank to offset those emission increases but the difference is that the money that they pay is not through a third party. They pay a mitigation fee to the district which we, in turn, turn around and reinvest it in emission reduction projects in the community where these power plants are being built.

MR. JASKE: Mr. Tollstrup, do you have anything you want to add to that answer, particularly with respect to smaller scale distributive generation?

MR. TOLLSTRUP: Well, I think there are a couple of things here. I think that essentially, a lot of the focus is on South Coast because the issues have kind of come to a head here but there's a larger issue of concern and that's the need for offsets and, you know, to start programs in the (inaudible). I think, eventually, it would concern some of the other districts which face various similar problems as the South Coast does. Certainly, with the distributive generation projects, South Coast does have a priority to reserve or did have that allowed them to access that, to obtain mitigation. In other areas of the state, that option isn't necessarily there. There's (inaudible) on the open market and then he was charged with total prior offsets and you'd have to go out there and purchase these ERCs in the open market.

The OTC is just kind of a subset of the larger issue that needs to be dealt with. And as Mohsen pointed out, the, a lot of these DG projects, distributive generation, aren't necessarily as efficient or as clean as some of the larger central station projects.

So, it depends on how much goes forward in a lot of the areas in the state addressing it and what kind of budgets received will see them. But it is an issue, I think that will come up in other areas. It's just a matter of time.

MR. JASKE: Why don't both of you expand upon certain stands that these power plants in the Mojave district using credits from South Coast?

MR. NAZEMI: In terms of projects outside our basin, under state law, there's a provision that you can transfer credits from an upwind down district to a downwind district provided the, non-attainment status for the bailment district is significantly contributed by the upwind district.

In the case of both Mojave desert and Antelope Valley, that is the case as determined by State Air Resources Board so the provisions exist for the transfer of these credits. And, in those two districts, there is practically no ERCs available. I understand that there may have been some created recently by the shutdown of a powered cement plant, however, in general, they don't have a bank of credits either internal or third party type credits and so, in the past, we have transferred credits for the High Desert project that the California Energy Commission licensed through the transfer of credits from our agency and, therefore, this is the provision that we felt like was already allowed under state law and so the changes we made to our new source review, prior reserve rule was to allow credits to be transferred again to the district's downwind in order to allow construction of these projects.

Our Board, however, does not endorse wholesale transfer of open market ERCs from our agency down to these two, down the districts because as I showed you on the slide earlier, that there's hardly enough credits available out there for projects that are not exempt from losses and they need economic growth. They need to have credits in the open market and we can't just allow one or two power plants to just buy all the credits in the open market and transfer it down to their district because our Board feels that that is not going to help the economy of Southern California.

MR. JASKE: So, in terms of these credits, credits from winds, downwinds, gathering from what the two of you said that that's allowed by state law but is there discretion on the part of the upwind districts to permit that to happen, to agree that that transfer should take place?

MR. NAZEMI: Yes, actually, in the state law, there is a requirement that both upwind and downwind district Governing Board has to have approved that we're making a number of findings. So there is a requirement that both of the Boards make certain findings and then, approve that to transfer the credits. However, just to close on that, the changes that we amended into our new source review rule which was adopted by our Governing Board, did incorporate an approval of the transfers from our internal bank to the downwind districts, not from the open market.

MR. JASKE: But if there is to be transferred, it’s not market ERC; it’s internal bank credits. I think this is a good time to ask you, Mr. Wanger, to give us a little bit of an explanation of the general role the Coastal Commission and, perhaps, you’ll give us what was originally required here is that as proposed. Mr. Nazemi referred to one of them. If I understand the Coastal Commission recently acted on the fifth on one of those.

MR. WANGER: Excuse me, the Coastal Commission has a responsibility on Coastlec to review any project in the coastal zone for its impact on coastal resources and compare those with the particular resource policies in Coastlec. Clearly, the, (inaudible) is that the Energy Commission has the sole authority for permitting and locating modified power plants with a grade of 50MW and as we’ve been talking about most of these plants that are under this, potential end of this policy, clearly are over 50MW.

However, under the Coastal Act, the Commission has express authority to participate in Energy Commission proceedings and make a series of findings of how a proposed project can be done in conformance or compliance with the requirements of the Coastal Act. And, so we would analyze the project to make a report with findings to the Energy Commission on how particular project impacts could be mitigated or addressed as part of the Energy Commission's proceedings. And then, because of, I guess, according to the Warren-Alquist Act, the Energy Commission must include those specific provisions in its final permit decision unless it makes one or two findings -- if they find that it's unfeasible or they would have a greater environmental impact from the decision.

The Coastal Act can also be administered by local government entities that have what's called a local coastal plan. They've essentially prepared a plan to show the Coastal Commission how it can take over a permitting authority in their jurisdiction, how their application to Coastlec would be compliant with the requirements of the Coastlec in a local planning and permitting process. In many of those cases and in most of the power plant issues that would come forward in a local jurisdiction, the Commission retains appeal authority to work on those issues as well.

An example of how this played out in recent years was the staff of the Coastal Commission worked with the Energy Commission on the proposed project upgrades at the Morro Bay power plant. The Commission made a series of recommendations that the Energy Commission staff also agreed with on how that project could move forward to look at phasing out once through cooling as an impact.

There we saw, as Mr. Bishop reported earlier, the findings that once through cooling has a significant impact on marine resources is of great concern to us. We're looking at the long term viability of coastal resources, marine resources, looking for ways to reduce those impacts. Obviously, we support the phase out of once through cooling and have been pleased to participate in this working group to try to find a way to achieve that objective in a way that is considerate and thoughtful of the needs of system reliability and to try to use the planning and permitting, purchasing process that's available through the energy agency's respective authorities to achieve that goal and objective.

I think one of the questions that you had posed to us was how do we perceive that, those issues coming to us? We, I was thinking about that but there is one probably one aspect in working with local jurisdictions and establishing long range plans, for instance, bringing a new transmission to an area that probably would want to be incorporating those ideas and plans into their long range development plans. So, it's probably a conversation to be had with local jurisdictions and the Commission as well on regional planning and local planning issues.

And, secondly, in being reactive to projects that are brought for us, forwarded to us for a Commission permit under the Coastal Act, we'd be looking to see how this project conformed to the policy laid out by the Water Board and how this project needs to be conditioned in a way to make sure that those particular project aspects are dealt with appropriately in a way that's in conformance with the Coastal Act and, obviously, as I mentioned before, in the old Coastal Act, we'd be making a report back to the Energy Commission about here's how this could be achieved in this particular case. I think that's the primary reason (inaudible).

MR. JASKE: So, do you, I guess, I'm going to ask this follow-up question. Since that the current (inaudible) power player, power plants would retire early and not be repowered in place and to allow that, there would be at least transmission development and the Coastal Commission would have a role in permitting that transmission facility?

MR. WANGER: For those, the area that's within the coastal zone itself, yes. Depending on the particulars of the project, I can imagine multiple scenarios reaching the 16 or so plants in our jurisdiction. But, yes, we have a role in permitting in that.

If we were part of a federal project, we might have other authorities under the Coastal Management Act to handle consistency review, to come in on that and just try to work with the project proponents on conditions that make that feasible for approval. But, yes, we would be permitting, working on permitting transmission parties in those particular areas.

MR. JASKE: Before we move on, Mr. Tollstrup, is there anything more, you know, in this general area of supporting new infrastructure that you want to make some (inaudible)?

MR. TOLLSTRUP: You know, right now, there are a lot of discussions internally to figure out how this is going to be put together. There's no, there's no single way of hacking this. I think that the, you know, we work closely with the districts and there's EPA as well to see if there's somebody to get right on some of the issues that are raised that at this point in time, we're still kind of scratching our heads trying to figure out which way forward.

MR. JASKE: Thank you. Question five raises the whole notion that if or "when" it is necessary for them, the (inaudible) plants to file for the permitting of power plants, then seemingly is this debate in (inaudible) analysis. Is modification and state implementation plan a feasible route to an impact, to create more power plants presuming, I guess, that some others emission source or sources were squeezed down tighter? Do you generally view that as a viable route to follow as far as a solution to new power plant builds?

MR. NAZEMI: I can take a stab at this. I think the answer is yes and, again, the changes that have been reflected in our regulations some time ago have all been approved into the state implementation plan by USEPA. The recent changes that we had incorporated in the 2000, early 2000, those were to allow again power plants to access our bank of credits with basically no limitation and those were approved into the SIP by the USEPA. And the most recent changes that we have made that have not been invalidated by the State judge, actually put in a much more stringent requirement on both criteria pollutant emissions and toxics emission depending on where the plant is going to be located, significantly more stringent requirements than those on power plants who want to access our bank of credits.

And, you know, we have been working with the processes that once we make changes into our rules, we submit it to the Air Resources Board first and there is actually requirements under state law that we can’t make our new source review rule less stringent so they evaluate it and in this instance, they actually, the Air Resources Board had, made that determination and forwarded these rules over to USEPA corridor, approval into the state implementation plan. But because of this court decision, there is some question on whether EPA will act on this at this point or not.

And, finally, I think it is important to point out that our program on offsets in general was created back in 1977 under the Federal Clean Air Act. Our agency actually had adopted these types of requirements under new source review earlier than the 1977 Federal Clean Air Act amendment. I don’t think anybody envisioned at that time that this offset requirement would be such that first of all, there wouldn’t be any offsets or enough offsets available for economic growth and, secondly, the price of credits would be exuberant to the point that right now, as I mentioned, we have some over a thousand permits pending.

These are like for back-up generators to be installed at a police station and in order to get their permit now, they have to purchase offsets in the neighborhood of $70,000 - $100,000 just for the price of emission reduction credits. So, I don't think there's any, wasn't any intent that this be the process for generating and providing offsets.

So our agencies began some work. We had to form the workgroup including the Air Resources Board, USEPA, our agency and the representatives of both industry and environmental organizations to look into what other solutions there are and initially make provisional changes to our regulation and state implementation plan to address that. And I think that's something that's not going to be, again, quick. We have, we're looking at short term, mid-term and long term approaches and depending on where we end up with those, I think that time will show whether they will be successful or not.

MR. TOLLSTRUP: And, I'll add to this one. I see this as two issues here. One, you ask if can you amend the SIP to put tighter controls on source and other sources to allow for power plant growth? I think that that's a real hard sell specially in areas like South Coast, the San Joaquin Valley, there's certain areas who can make that commitment under state federal law to get reductions. And, quite frankly, in those areas, there are not technologies there to get where they need to be. So, I think that you can, you know, add additional control to existing sources.

The districts have already adopted rules and gone, you know, as far as they can on most sources though they may be somewhat a few there but normally -- So, I don't, that one just doesn't pass the straight face test. I just don't think that given the real issues that they have on those areas, this just would not work.

The second side of that is the new source review side which Mohsen touched on. There is a provision in state law that says that the state has to review the district's NSR rules and the banking is included in that review. And it basically says that, you know, you take the rules that existed back in December 2002 and you look at any changes they made in the requirement. If there's a relaxation -- anytime, a relaxation -- we disapprove the rules and the districts can't move forward on it.

So, anytime they go looking at -- and this is part of the problem -- is that looking for flexibility or trying to create additional reductions or additional flexibility under new source review, you know, that, it's going to be harder not to show that that isn't a relaxation of the rules. So, you know, in trying to work with the districts, we've been working closer to the South Coast on a number of ideas. They have, the (inaudible) passes the straight face test but I think there are issues on both sides either controlling existing sources or going beyond SAR (inaudible) that we have to, that we have to deal with.

MR. JASKE: As indicated earlier, you provided the other districts whose their credit situations are blown up, publicized (inaudible) South Coast that might be sort of on the horizon. Can you identify where those are? In particular, are they, you know, in locations where all these existing OTC plants are?

MR. TOLLSTRUP: Well, one that comes to mind would be San Diego. San Diego's had issues in the past on the, in fact, they were trying to get some power plants built down there like I'll take Mesa. We have (inaudible) the offsets for that project down there. That situation has not changed. They still have an issue down there.

The other districts going up the coast, I don't, I don't enough information to answer that but we suspect that it will be an issue, eventually. Anytime you have to provide offsets for a large stationary source (inaudible) credits purchasing (inaudible).

MR. NAZEMI: Doctor Jaske, I think just a last point to add to this. I think that it is important to consider when, when I mentioned that our Governing Board made changes, amendments to our rule to allow power plants to access our bank of credits, again, it wasn't for the sake of just building power plants in South Coast.

When we had an early 2000-2001 energy crisis, we saw what happened. We saw a couple of diesel back-up generators started to run and, you know, our agency's responsibility is to protect air quality and public health. We don't find that as a good solution to not building power plants. So this time, when the Energy Commission came up with a projection that there will be again a shortfall in the coming summers, our Governing Board felt that we better be pro-active rather than be reacting to calls from Governor's Office to allow power plants to track up their NS30 whole units and run over their permit limits and requirements. So, we were trying to prevent a worse disaster rather than just build power plants in South Coast and that's why our Board adopted these changes.

MR. JASKE: Oh, I think we largely crept to last question, question six. Things are underway. You indicated, Mr. Nazemi, that for example, the South Coast is working right now to try to rehabilitate part of Rule-1315 and 1304 through your own regulatory process and you've also identified this legislation that South Coast has sponsored. Are there other things that district hasn't relayed, you know, that we should know about in context of this question we're here today?

MR. NAZEMI: The only other thing I would add is historically, emission reduction credits or ERCs have been generated from sources like a factory, a power plant or other type of stationary sources.

We are, as we speak, in the process of looking at what other sources of emission reductions are there, typically non-conditional sources that we are in the process of actually developing a few regulations that would allow additional ERCs to be generated and those include road paving, one of the main ways to generate emission reduction credits. The other one we're looking at is we have Metrolink as one example. It operates on (inaudible) engines on their trains where they pull into the stations. They're running dunes typically are diesel powered engines to provide light and air conditioning to trains and we're looking at how we could, how we could have those units replaced with cleaner technology and a reductions, cleaner emission reductions.

And, finally, we've been working with a number of sources at the port in terms of this is ships that come into the port to look at abilities to once they hook up to the dock, to shut down their boilers and diesel generators and use either shore power, cold ironing and if they can, in their units are now being provided that would go over and beyond what their resources for regulation requires, goes up the percentage of ships that have to be converted to shore side power.

And, in addition, we are also we have permitted a project where the air pollution control system that is right now, it's on the shore side and what they do is that they have a bonnet that's like the hood that they put on the top of the stack of the ship as it's sitting at the dock, running their engine, to pool all their emissions they do and air pollution control system and they've tested those units and they're in the 90 plus percent efficiency in terms of reducing the air pollution and consented by the use of these types of technologies, we're looking at regulations to adopt to allow them to be also bring their emission (inaudible).

MR. JASKE: Mr. Tollstrup, anything you want to add?

MR. TOLLSTRUP: I think (inaudible).

MR. JASKE: Mr. Wanger? Anything else that comes to mind in terms of the (inaudible) restrictions of the Coastal Commission?

MR. WANGER: No, not much to add. I think we're trying to work with local governments as much as we can in looking at the long range development plans. I think any of the new infrastructure as I mentioned in the forum would begin to think about what those conversations might be, how we could perhaps facilitate conversations with local entities about proposed changes in infrastructure within the area and how they can incorporate that into their planning process for their communities.

I think it would be, specially for Coastal Communities, they have a few other things on their plate besides, besides this we see what issues their efficiency level rise and their impacts on local economies and infrastructure. And it would probably be yet another important part of the conversation they need to have. So, perhaps, we might talk about going about how we might facilitate that conversation.

COMMISSIONER BYRON: Doctor Jaske, may I ask you a couple of questions?

MR. JASKE: Okay.

COMMISSIONER BYRON: Mr. Nazemi, you'd indicated there's other ways you're looking at creating emission credits. I couldn't help but think that those aren't necessarily stationary, trains and ships. Do those fall under your jurisdiction?

MR. NAZEMI: You're absolutely correct that our primary jurisdiction is stationary sources. However, the emission reductions can be generated from mobile sources on their own regulations. That doesn't mean we regulate them but if they voluntarily want to come in and apply for emission reductions, then we can regulate them on their terms of either a permit to enforce the requirements or some sort of an agreement to enforce the requirements. Typically, the USEPA does not like agreements. They like to be either a permit or a regulation and that's why we're allowed some regulations.

COMMISSIONER BYRON: Too bad we can't go after those mobile sources that's the biggest polluters of all in this way, namely, automobiles. Mr. Wanger, you may have addressed this so I may be repeating when I ask but would the Coastal Commission seek additional conditions other than the ones that addressed once through cooling in repowering any existing power plants? Is that what you're implying with your comments that there would be a number of additional conditions that the Coastal Commission would require for repowering?

MR. WANGER: Well, I think it depends on the nature of the project itself if, for instance, there were impacts from the project on sensitive habitat, aside from particulars or if they affect public access or what probably went on from the proposed development. And then, we would look at conditions to address those issues but it would be done in the context of here's the package of things that we need to be done to bring this particular project in conformance with the Coastal Act.

COMMISSIONER BYRON: Well, I think you know that and certainly my tenure at the Commission, we're not going to, we're not going to license power plants that have run-off, have unmitigated impact on the environment. I think what I'm trying to get to, specifically, is is this going to be seen as an opportunity by the Coastal Commission to essentially implement conditions on a repowering of a coastal plant that would basically prohibit it from being able to be repowered? In other words, are you going to go after more than just once through cooling when you have the opportunity to do so?

MR. WANGER: No, I don't think -- the short answer is, John, (inaudible), no. I don't believe our Commission would do that. We would, especially given the constraints that we have in the Coastal Act and the Warren-Alquist Act, we'd be making serious recommendations about what we think would be the most appropriate set of conditions for this project but we wouldn't be seeking to impose those above and beyond what is necessary or is allowable at the moment.

COMMISSIONER BYRON: Thank you. Thank you. Mr. Nazemi, one more quick question, if I may? Do you see this issue as once through cooling, is this issue -- I call it the once through cooling priority reserve nexus issue here -- do you see this issue being solved in the absence of any kind of settlement of the parties in the litigation?

MR. NAZEMI: Well, the, there are a couple of other ways that this could be solved. One is, as I indicated, there is legislation that is pending. In fact, it goes to the (inaudible) committee tomorrow.

COMMISSIONER BYRON: Right. There's actually two pieces of legislation but they only affect a limited number of power plants.

MR. NAZEMI: Actually, SB696 affects all. It's not limited. The other legislation, (inaudible) legislation; you're correct. It applies to maybe just one power plant. So that's one way but it's fail/pass and it allows those repowering and new power plants to be able to move forward.

The second way that this could be done is, as I indicated, we are readopting our NSR tracking rule. Once we have that rule, we adopt it and provided we withstand any further challenges which probably (inaudible) to tell about, what that rule does is allows -- it doesn't allow for new power plants to be able to be built but if it is an existing facility that is going, undergoing repowering, that allows our exemption rule which has been in place and has not been invalidated by this judge to utilize the exemptions and through our new tracking rule, we would account for those emission increases offset those accordingly.

So those are the two ways beyond priority reserve that include a lot of the once through cooling to move forward.

COMMISSIONER BYRON: Thank you. Any questions, gentlemen? Are we hungry? Doctor Jaske, thank you very much. Is there any other questions that you want to ask?

MR. JASKE: No, Commissioner.

COMMISSIONER BYRON: Well, thank you all very much. Let's go ahead and adjourn for one hour. We'll restart at 1:30, on time. Thank you.

(Whereupon, a lunch recess was taken.)

AFTERNOON SESSION

MR. VIDAVER: Welcome back. You all know (inaudible). This Panel this afternoon is a discussion with a group of representatives from Merchant Generators participating in California's market. Regulatory agencies will no doubt be around forever hopefully implementing well informed decisions, utilities (inaudible) the consequences as (inaudible). Merchant Generators may not be here forever. They have the option of getting up and walking away if the regulatory processees of redesign don't facilitate investment in California's electricity center.

MR. LEUZE: Mr. Vidaver, you make it sound like their departure is only voluntary. Sometimes it's not voluntary.

MR. VIDAVER: This is true. But nevertheless it has to craft a regulatory process and environment in which they can thrive (inaudible) last ten years might be considered by some to be a waste.

So we have representatives from five entities which own OTC Generation in California. I'm going to take the liberty of introducing them. Eric Leuze from Reliant is here. Reliant owns Mandalay and Orland Beach in the Big Creek Ventura load pocket. Sean Beatty with Mirac, which owns the three facilities in the San Francisco Bay

Area of load pocket. Randy Hickok with Dynegy, which owns South Bay in the San Diego load pocket and Moss Landing and Morro Bay the two units that are not located in a local reliability area. We have Eric Pendergraft with AES, which owns Alamitos, Huntington Beach and Redondo Beach all in the LA basin local reliability area. And Jesus Arredondo with NRG, which owns El Segundo in the Los Angeles reliability area and Encina I believe in the San Diego local reliability area. Each of these gentlemen has agreed to appear here and respond to a series of questions, which they received.

I’m going to go through them one at a time. I’m going to slightly restate them so hopefully my question will capture the essence of the question that they are prepared the answer.

The first question deals with measures that may have been taken at their facilities in order to comply with any near term requirements for mitigating the impacts of once through cooling. Near term being that period of time prior to the implementation of the policy which requires the elimination of once through cooling.

That being said there are a couple of ground rules. As I mentioned earlier this is not a forum in which we are going to debate the wisdom of the State Water Board Policy and you may be tempted to talk about the wonderful things that your facilities can do as currently continued and the incredibly important role that they play in meeting California’s energy needs, but we’d appreciate if you’d keep the cheerleading to a minimum. So with that being said, I don’t know how you want to do it. Maybe Mr. Leuze who’s sitting closet to me (inaudible) first.

MR. LEUZE: Thank you, Dave. My name’s Eric Leuze and our company is RRI Energy, formerly Reliant energy. And first I would say we’re committed to fully complying with all applicable laws and regulations and to minimizing the adverse environmental impact of operations.

With regard to the design of our facilities the Orman (phonetic) station has an offshore intake with a velocity cap and then excluder bars and these facilities substantially reduce the impingement of (inaudible). The Mandalay station is at the end of a manmade canal and harbor system and so that largely reduces the impacts, of course, if that pumping did not occur then there might be some detrimental impact on the bay and the harbor.

With regard to measures that we might undertake, I guess first I’d like to point out that both of these plants were designed as base load facilities and over the years due to the economics of their operation they operate quite a bit less and the corollary is that the circulating water pumps are not on as much and so when they’re off line there's no water being pumped through the facilities. And as the ISO presentation illustrated, these facilities are still critical to grid reliability operating at the peak. And, of course, during those times they are pumping water through the cooling system.

So that's the exiting design and exiting operation. There are other measures that we could undertake and were, did a preliminary look at measures, such as variable speed drives to further reduce the pumping volumes and associated environmental impacts when the facilities are operating. Of course, the economics of such investment would have to be supported by market revenues, which maybe we can talk about a little bit later.

MR. VIDAVER: Very well. Thank you. Mr. Beatty.

MR. BEATTY: Thank you. Yeah, before jumping into answering the question just a few high level remarks. One is as we work through adopting a policy here with respect to once through cooling is, and I think this will become apparent as the generators go through their discussion points is that there is uniqueness to each one of the facilities and we really are concerned that the effort to craft the one-size-fit-all approach is not the right way to go.

And along those lines we think that if there is a policy adopted, and I understand we're not here to debate the merits of that policy, but if there is we think a prudent thing to do is to make sure that there is some kind of re-opener or re-look substantially too far in advance to make sure that grid reliability is assured to prior to any of these planning going out flying. So those are the two high level points I just want to make quickly before jumping into the answer.

With respect to merits specifically, since 1994 we've actually retired nine of our once through cooling units that comprise about 1300 megawatts of capacity, and those units were once (inaudible) so they're no longer online and therefore, they no longer draw water from the Delta, so there's significant environmental impact production right there.

We still operate five units in California that rely on once through cooling. There's two units in Contra Costa, two units at Pittsburg, and then of course, the infamous Portrero facility. At those units we've deployed variable pump technology, which scales the volume of water used to the amount of electricity being generated.

We also, in the Delta units, which are the Pittsburg and Contra Costa plants, we operate subject to the Delta dispatch requirements, which essentially state that there's a preferential dispatch order that relies on Pitt unit, Pittsburg unit seven, which is a non OTC plant, before dispatching the once re-cooled plants that are there. As a result we've seen a 90 percent reduction in the use of water in our Delta plants since the early '90s. So that's kind of the historical view of what's going on at those particular units.

And I really think that's an important point because listening in to some of the discussion about the once through cooling bill, SB42, there was statistics that were used that dated back to 1978 the created a fairly bleak picture and the fact that we reduced water usage by 90 percent would suggest that the data from 1978 is really not germane to the discussion at this point.

And then finally, in terms of the types of things we're looking at going forward is we have looked at the possibility of using cooling towers at the Delta units and that review is preliminary, but we recognize, you know, kind of the direction that the State is headed and we're trying to evaluate all the possibilities.

MR. VIDAVER: Mr. Hickok.

MR. HICKOK: All right. I'm Randy Hickok. As you said, I'm with Dynegy. We've got three coastal power plants, South Bay, Morro Bay and Moss Landing. And regarding what we're currently doing to reduce the impacts of once through cooling. Morro Bay and South Bay have rotating screens, (inaudible) bars, obviously that's per the water permits, there are several limits on the differential, the (inaudible) water (inaudible) plants and leaving the plant.

We also did have units one and two at Morro Bay, which we put into mothballs I want to say somewhere around five years ago now. So water circulation at the Morro Bay plant is down (inaudible) from any stats that would have been germane in the '80s.

At Moss Landing, Moss Landing is in my mind like having two plants. We've got 1500 megawatts worth of conventional boilers then we also have about a 1,000 megawatts of combined (inaudible) power plant we built up in the parking lot around 2002. And they have separate (inaudible) structures. Units six and seven have protected measures similar to that of Morro Bay and South Bay with the inlet screens. I know that prior to our taking possession of Moss Landing PG&E had finished retiring unit one through five and relocating the outcall structure from the Elkhorn slough out into Monterey Bay. Thermal limits are in place.

What's unique about Moss Landing would be the new combined (inaudible) and we have one of the few combined (inaudible) plants that was permitted recently using once through cooling. The intake structures there are slanted screens type so they have lower intake velocities than our other facilities with that similar restrictions on thermal impact. One of the aspects of Moss Landing units one and two was part of the CEC conditions to get our AFC and build the plant required us to pay mitigation that the intent of which was a one-time payment to offset the detrimental impact to marine biology over the life with the (inaudible). So those payments were made back in 2002 to the Elkhorn Slough Foundation that purchased a lot of land then there's been some mitigation around the Elkhorn Slough.

We've got a lot under study, but nothing that's (inaudible) to so consequent.

MR. VIDAVER: Mr. Pendergraft (inaudible).

MR. PENDERGRAFT: Hello. Eric Pendergraft with AES. We own Alamitos, Redondo Beach and Huntington Beach, all in the LA basin about just over 4200 megawatts I think, depending on what statistics you use. It's just short of 20 percent of Southern California Edison's peak demand.

We have velocity caps in place on Redondo and Huntington Beach intakes. There are, you know, studies indicate that they reduce impingement by approximately 80 percent. The canal intakes at Alamitos are manmade, as

Eric cited, for one of the Mandalay plants so they don't limit themselves to that velocity cap installation.

You know, as we've seen today the units run a lot less than they were designed for. If we look back at our 2008 operating profile and take our actual sort of circulating water flow volumes, which should be proportional to entrainment and impingement. We're about 70 percent below what the plants are permitted to run at.

And I think there's still a little misconception or misperception out there that when the plants are off line we do in fact shut down our circulating water system. Those pumps, except for very unique circumstances, the pumps are shut down and there are no entrainment and impingement impacts when our pumps are not operating.

The other thing you saw I think with David this morning is these facilities spend a fair amount of time operating at minimal loads so they're therefore spinning reserve. We've been experimenting with, each of these units are supplied by two circulating water pumps, and this is a little bit of a poor man's veritable speed drive experiment. But we've been experimenting with shutting down one of those circulating water pumps when we're at minimal low, which would directly reduce the impacts by 50 percent. And given the amount of time we spend operating at minimal low that has a pretty significant benefit.

We have performed high level retrofit studies for closed cycle cooling, both wet and dry cooling. As one might expect there are significant land constraints as well as permitting issues. They're expensive, you know, a rough ballpark for wet cooling at our sites it's approximately $125 or $115 a kilowatt. So for our 4,000 megawatts you're looking at, you know, 500 million dollars, half a billion dollars to retrofit with wet cooling. It's about double that for dry cooling if you could in fact get it permitted and built.

We've heard about the associated efficiency and other impacts so I won't highlight those.

Like Dynegy we spent five and a half million dollars on a wetland restoration project to offset our entrainment impacts for Huntington Beach three and four. That restoration project is just about completed. For the first time since I have been around we've got title closed in the wetlands that's adjacent to our plant, so that's pretty encouraging.

And then finally, we are bartering with West Basin Municipal Water District to do a desalination demonstration project. Part of that demonstration study will include testing one millimeter and two millimeter wedge wire screens. So that's a yearlong study. It's, you know, being basically done by the Municipal Water

District given that they're a public agency. Those results will be public, which answers one of the questions here, so that's another technology installation that's we've seen evaluated as part of the desal [sic] project so.

MR. VIDAVER: Mr. Arredondo.

MR. ARREDONDO: Jesus Arredondo for NRG. Similar to what my colleagues have already said, NRG has engaged similar practices, velocity, caps that actually have proven very effective at our El Segundo facility reducing entrainment and impingement by more than 90 percent. Pump shut downs whenever it has been practicable, we've done that as well.

At our Encina facility, which is North San Diego County, we've coordinated our operation whenever possible with Hub Sea World. We host a white sea bass hatchery. So whenever there's planned releases that typically occur once a year, we do try to coordinate as best as possible to avoid any entrainment and impingement. That's what we have.

What we're doing today, the future NGR we have I think discussed (inaudible) at this Commission because we have gone through at least one AMC proceeding now all the way through. One that is newer for El Segundo despite having actually obtained an AMC for continued use of (inaudible) and came back to the Commission and voluntarily opted to update our permit and this time come back around appealing for a permit modification to non once through cooling in the future.

Now unfortunately, while we have secured a, participated in RFO and secured a contract that went forward for ten years it’s been (inaudible) in the south coast, their quality management (inaudible) problems and we’re participating in that process of trying to identify a solution legislatively hopefully to explain the success alluding to that. I think that you are too.

The Encina project, that AFC we came in to the Commission and that one we’re coming in for a non once through cooling in the future. And we have a little bit of experience with transitioning in that we appealed to the Commission and asked that the Commission not exert it’s jurisdiction when we retrofitted our Long Beach facility for non once through cooling. We were under the megawatts so the Commissioners, thankfully, obliged us and said we won’t exert jurisdiction.

So we’re moving forward and looking to the future, but it’s very important to note that while NRG has been able to do this at our facilities something critical that Dynegy and others will agree on this Panel, one size does not fit all policy to impact. All of this will not work for all of us. NRG has been able to do it because we have the space and because we've chosen specific technologies that might not be good for others and where the space might not be available at other facilities. But at least for us moving forward without once through cooling is something that's hopefully going to happen and the sooner the better obviously.

MR. VIDAVER: Thank you (inaudible).

MR. HICKOK: David, could I --

MR. VIDAVER: Yes, sir.

MR. HICKOK: -- could I fall back a minute to talk about what we're doing prospectively. I just remembered --

MR. VIDAVER: Sure.

MR. HICKOK: -- what question two is all about. Something we're doing, nothing regarding what we'll do prospectively and our anticipation is that time will shut down once it's no longer required for must run purposes and that would predate 2015 or whatever the target timeline is, so there's no activity at South Bay and Morro Bay given the vintage of that plant and how seldom it runs.

They're looking at what it would take to replace the existing pumps with variable speed pumps right now when the plants running. The pumps run at one speed. We can replace that with variable speed pumps and we would move less water in the plants. It's running at minimum load versus max load.

At Moss Landing we're also looking at variable speed pumps, although I don't think it'll make as big a difference there because Moss has a number of pumps at the plant and (inaudible) goes on sequentially as load builds and the like so you'd be getting a little (inaudible) benefit, but not a great deal at Moss.

At both Morro Bay and Moss Landing we'd be looking at screen house retrofits depending on what water speed you want across the screen. At both Morrow Bay and Moss Landing we did a lot of very specific investigation into those locations as part of the CEC permitting process for units one and two at Moss and then we were hoping to build a similar plant at Morro Bay.

So we already have in place a very extensive record regarding the feasibility of using dry cooling, wet cooling. We're in the process of dusting those studies off and updating the cost, but I think we understand well what's feasible and what's not feasible there. I think in both of those plants due to PM10 issues wet cooling is not an option and that Morro Bay given opposition by the City of Morro Bay no closed cycle cooling is an option.

Two that are a little unique, at Moss Landing we just sent a RFO out to the Moss Landing Green Laboratories asking them to conduct a study as to whether water could be drawn from deeper in the ocean. Right now we pull it out of the harbor. The notion there is that 90 percent of the living organisms in the sea water are located relatively near the surface and so we're trying to discern whether there is a location deep enough under the surface of the ocean that we'd pull, it wouldn't be sterile water, but it would have the (inaudible) less marine biology in it than the waters that we're drawing off of right now.

And that might be viable at that location because the trench (inaudible) Marine Canyon there (inaudible) Monterey Bay drops off precipitously just a couple of hundred yards off the shore, so that might be an option open to that plant that isn't open to others.

And another crazy idea that we've got is what if you just made a closed cycle cooling system, but have the, effectible you'd be linking with pipe your intake and your outtake structure, so you would be circulating water through the plant. You would have no impingement or entrainment, you would still have thermal issues, you know. That's a wild enough idea that we're not sure whether from an engineering standpoint it's even viable, but we're checking it out.

MR. VIDAVER: Thank you. Well it’s a, you proceeded to ask, you know, answer a good part of the second question. The (inaudible) it’s dated that’s right.

MR. MANSOUR: And just the kind (inaudible) actually some of the data, some information which is (inaudible) from this down. Let me circle back to what the environmental agencies have said, and in fact to kind of connect the two as to whether there is a link, possible link or not and I’m going to consider that they might leave before we ask the question while we have them in the room.

So I heard Mr. Bishop saying that your open for suggestions that you want to see hard lines and commitments and the rest of all the Commissions. From what you heard from this Panel in terms of attempts to reduce the amount of intake so your 15 billion gallon a day, if there’s a target let us say to reduce it to, I don’t know, 10 billion by a certain date or something like that (inaudible) come through cooling or any of the (inaudible) that you heard from them, would that be the kind of flexibility that you’d be (inaudible) taken or no? Is, we’re talking about I think the (inaudible) or other (inaudible)?

MR. BISHOP: You know there’s not an easy answer to that question, but I’ll give it a shot, which is that our approach will be that you could get there with ultimate technologies as long as you actually meet the target goal reduction. So what we're, what we looked at in the initial, and what we're proposing to put forward is since a track one would be closed cycle wet cooling, which requires some makeup water so you have a certain amount of water that comes in and you have your (inaudible) associated with that. Or under track two it would be 90 percent of that.

The one area that I would caution folks is that if you're thinking you're going to get to 90 percent by looking back at your initial capacity at the plant when it was built and, you know, at that point you could run this thing, you know, 100 percent of the time, you'd have this huge volume of water coming through, but now you don't run it five percent of the time so you've made 95 percent reduction and so your (inaudible) is not what we're looking at. We're looking at is what were you running the plant at and if you didn't have this controlled technology or this different approach can you reduce it down to within ten percent of what it would be for wet cycled (inaudible). Did I answer your question? (inaudible).

MR. MANSOUR: But we're talking about impact. (inaudible) let's just not go through talking about the impact of (inaudible) cooling.

MR. BISHOP: Correct.

MR. MANSOUR: And what I'm asking is can we target the impact rather than the technologies? So we could say like you heard people say talking about variable speed motors and pumps and it would take the (inaudible) level (inaudible) and all that's all reduction and even the number (inaudible) looks like from what I'm hearing is that that's a very old number not taking into account all the stuff that have changed since then if the industry demonstrates.

Again, we're not talking about like in plant lines holistically to reduce the intake, let's just say one example, by so much a certain day, which is (inaudible) so I can (inaudible) responsible. Would that be the kind of flexibility that should be opened?

MR. BISHOP: Yes.

MR. MANSOUR: Okay. Great. Now I have a second question. Hearing the issues that we in, okay, when owners have tried to solve the OTC issues by making change by which they would have to go through (inaudible) and the (inaudible) kind of say, well this is a different problem. Now you've seen what the (inaudible) between the agencies and (inaudible) resulted in a coordinated effort known as (inaudible) and it pretty much, and with your help as well and your acceptance we wish that, you know, something was going to (inaudible).

Is there an effort between the (inaudible) agencies between water, state water, regional and air by which the things that you're looking at in (inaudible) climate change of environmental impact holistically so one would know that this is for that purpose (inaudible) say there's some relaxation in my rule to meet this and then it would reverse maybe another attempt from other regulation? Is it, is there a (inaudible) other agencies?

MR. BISHOP: There are ongoing efforts on climate change issues on how different regulations (inaudible) climate change. So in general, yes, we are part of that kind of discussion.

Meaning specifics, have we met with the air board to say, look, you know, we have these rules going on you have those rules, we need to figure out how to coordinate those only in so far as that we've asked the air board to be part of our working group. We have not gone the next step, which we may have to to say, okay, now we have some sort of a proposed scheduled plan that we're moving forward on we need to coordinate your activities with ours to make that work. I would expect that we will need to do that as we move forward, but it hasn't happened yet.

MR. MANSOUR: Can we count on it?

MR. BISHOP: Of course.

MR. MANSOUR: Now, just before, now (inaudible) back to the Panel, if the Water Board is with their own understanding, and believe me, (inaudible) this issue for like almost two years and I have that knowledge, the flexibility they have demonstrated and the time and understanding to the point where we're really making progress with it. So I know you're really sincere about it and that's over the many months or over the two years (inaudible) great progress and understanding of the issues and being reasonable in terms of you want to move on at the same time you have full understanding what the impact is.

Did the rules come out like, we're talking just hypothetically, that is in terms of reduce the impact (inaudible) by certain time rather than the technology per se. Among us, and we're talking about the whole industry, is there a way that the recent community can coordinate that and actually see that that is something reasonable that you can work with?

The thing is I'm concerned to understand it when you say every one of us is different? Just say, okay, the other (inaudible) think industry as a whole and we're asking them not to be specific and say this plant by this date, this plant this date, this plant by this date. I want to provide flexibility to deal with the impact as a whole. How can we make that happen? The (inaudible)? Any suggestion?

MR. PENDERGRAFT: Well I think that (inaudible) was obviously in the details. I mean we've got, you know, I think there's sort of three groups of units in my mind. There are the nuclear units, which as a consumer and a rate payer I think should be allowed to keep their once re- cooling system in place and we need to figure out a way to do that and mitigate for their impact or, you know, something --

MR. MANSOUR: And let us (inaudible) --

MR. PENDERGRAFT: -- (inaudible) beyond the (inaudible) --

MR. MANSOUR: -- for one.

MR. PENDERGRAFT: Okay. As you've seen by the data there's a large group of these facilities that are really only needed for summer peaking. And that's when they run. And their impacts are relatively less significant than some of the other units.

And then you've got this select group of plants in local reliability areas that are vintage that are needed year-round. If we're really trying to, you know, consider the marine environment that is the subset of plants that we ought to get transitioned to new technology. And you want those plants that are required year-round to be the plants that don't have once through cooling and that have newer technology.

What that will do is push, it will push those plants that continue to operate now around the clock into the group that is only needed during summer reliability.

MR. MANSOUR: I guess just what I'm saying is, let us say that the Water Board is (inaudible) for a holistic impact reduction, water intake for example, and knowing that each one is the, and we want to them just to persuade them to stay away from being very specific plant (inaudible) plant of a certain day. How can we coordinate that to the (inaudible) industry so that is achieved? The impact is reduced (inaudible) so we can be (inaudible) rather than leaving it say, you know, it depends on all that stuff, but then at some point in time they have to move forward. Any ideas?

MR. HICKOK: Well I think an emphasis on mortality as opposed to say just a body of metric flows is a step in the right direction. You know, the change in volume metric flow you're kind of presupposing the means by which you're going to get the reduction, which is a retrofit with close cycle cooling. So it is (inaudible) producing without reducing the mortality will tell us what that benchmark is and then you can find that there are other technologies that will allow you, give you an equivalent reduction of mortality that may or may not have anything to do with volume. I mean there would be some relationship there. But that’s off the top of my --

MR. MANSOUR: Any suggestion (inaudible) second? Can you coordinate that? Do you think the industry can coordinate that?

MR. ARREDONDO: Can we have coordination, better coordination form the State as well because there have been meetings that have occurred at agency levels where we have been excluded and a good indication of that is that fact that 1978/1980 numbers are still being used by which to measure us. So a greater transparency, greater inclusion by the State agencies as we approach these changes in regulation are required so that we can have that ability to, not only participate but offer, you know, some of the changes that we’re making now. But I think that we could probably get to something.

MR. BEATTY: You know, adding on to those thoughts is that I think that the generator community is only a part of the puzzle. I think that the agencies have to be involved in creating an environment that allows certain decisions to be made going forward and I also think the utilities have to be part of the solution as well because they're ultimately by and large the ones procuring the energy and providing the (inaudible) which maybe some of this investment can get made. So to say it's just the generator community that has to come together to figure out the problem, I think that's actually just one of the legs of the three-legged stool.

MR. VIDAVER: Thank you.

COMMISSIONER BYRON: Just if I may, just going off the last comment you just made, do you see procurement as being a key aspect of how we might address this issue as well, Mr. Beatty?

MR. BEATTY: I do actually. I think that there's, well I was going to lead into this in one of my later answers, but I think that, you know, there are some scenarios where we could put some investment into these units and maybe actually get them off the river, so to speak, and but part of the solution to that investment is a procurement process and we're not sure right now that the existing procurement vehicles allow us to make that investment.

MR. LEUZE: Well we --

COMMISSIONER BYRON: Well, yes, go ahead. Go ahead Mr. Leuze.

MR. LEUZE: I was just going to, just add a thought that there are (inaudible) tradeoffs that has to be considered here and I think Mr. Mansour pointed out that one trade off is not reliability. That has to be maintained. But then we think about well what level of reduction in impact on marine life is the right target I would ask the question, how is the impact on marine life balanced against the other impacts caused by investment in other resources? For example, if you, and let me just, I'll state it quickly, if you by rough calculation would take about 20 square miles of space to replace our 2,000 megawatts of plant with solar thermal or hundreds of wind turbans and the associated impacts of sensitive desert habitat or rafters. I won't go into the numbers. I calculated it based on CEC data.

But, and I think Mr. Beatty hit on a key point though, with respect to any investment that we make it will be helpful to have a better basis for projecting what revenues we would be able to earn. For example, a multiyear forward resource adequacy structure would be particularly helpful.

MR. VIDAVER: And we'll focus on that in a later question, as you probably know. I just want to get some clarification from Mr. (inaudible). You implied that you can't get a 90 percent reduction in water flow over current levels without going to closed cycle cooling, but you implied that you might be able to get to a 90 percent reduction in damage using alternative technologies.

MR. HICKOK: Well again, if, you know, we don't know that this concept proves out, but if a deep sea intake accesses a portion of the marine environment where there are relatively few organisms by moving the intake at the plant I might be able to reduce organism mortality 90 percent relative to what my current operations are. Better (inaudible) and structure that just dictated a 90 percent reduction in the flow that rules out that technology. So again I think it's all about reducing mortality and so that you just need to be careful about the way you draft the regulations.

MR. VIDAVER: And the Panelists would agree that 90 percent reduction as well is only possible (inaudible) closed cooling. It's just --

MR. BEATTY: From our prospective we actually have already seen a 90 percent reduction. But when I hear Mr. Bishop it sounds like none of those efforts will really be considered. I think to get an even more 90 percent reduction you're probably looking at tons of cooling air.

MR. HICKOK: Yeah. And I'm not aware of any technology that would get you, if the benchmark is 90 percent of what you're doing now, well, you know, I've got a plant that runs five days a year, you know, if I got to scale that back ninety percent that's left over.

MR. VIDAVER: And (inaudible).

MR. PENDERGRAFT: Well and the point I was trying to get to was trying to get is if you are looking at it for industry wide you take the facilities that run the most year-round and you attack those facilities and replace them, which include some of our facilities, and eliminate the once through cooling you've now achieved enough reduction overall to compensate for all the other units that don't run very much. But you can't look at it on a unit-by-unit basis. You need to look at it industry wide, which is I think what you were suggesting.

MR. VIDAVER: Attack is an interesting word. Let's turn to closed cooling. In the cases of your individual plants do you see that as, your individual facilities, do you see that as an impossibility or possible? If it's impossible is it due to engineering realities or (inaudible) position for lack of a better word, and if it's technically feasible can you imagine the circumstances under which your costs work out and what obviously you would need some kind of recovery guarantee to lock (inaudible) contract. And is it conceivable if there aren't any engineering constraints and either your plant could do that or you can see that as possible and your theoretical sense where some people perhaps?

MR. LEUZE: Well, I'll answer briefly. The closed cycle cooling or air cool condenser options we have looked at for both Mandalay and Orman. They are expensive and particularly for the Orman site, which is a relatively small site. It would be, construction would be very difficult. There are also significant impacts in terms of power output capability and efficiency, ten percent or more impact on degrade. No, we're not optimize that, but it's very significant.

And, you know, the plain fact is once through cooling is a very efficient cooling system and allows heat rates that approach the emission performance standard for CO2, you know, which is about 9400 Btus per kilowatt hour when using natural gas and (inaudible) our plants are in the neighborhood of (inaudible). So obviously a ten percent increase in heat rate has a GHG implication. So we wouldn't say it's impossible, but it would be expensive, it would be at least in that respect countered to GHG goals and we would require some confidence that we'd be able to recover the cost of that investment.

MR. VIDAVER: I would assume you've seen the processing that's done by third parties in this. Do you think they're significantly understated in just your plants or do you have any basis for --

MR. LEUZE: I think they're understated, but I, you know, we have to refine. Ours is a plus or minus 30 percent estimate and --

MR. VIDAVER: Thanks. Mr. Beatty.

MR. BEATTY: So just to make sure we're answering the same question, the question that was originally positive was do we agree with the staff assessment that's generally kind of infusible to refit with cooling towers and I think this goes back to my initial point, which is I really think you can only look at it on a case by case basis. And I know some of the studies have really looked at it more generally and come to the conclusion that generally speaking cooling towers are not possible.

We think that merit that there are some scenarios actually with our Delta units where we could refit them with cooling towers, but, you know, the reality is that the economic viability of this here depends upon the vehicle for recovering the cost of the investment. You know, whether it costs out, which I think is along the lines what you're asking, Dave, was kind of depends upon what you, how you measure it. If you look at it compared to a new power plant we think actually it does cost out pretty well.

So, you know, I guess the message there is we think that there is a possibility, at least with the merit plants in the Delta region specifically, but in the absence of certainty regarding how those costs are going to be recovered, the investment, is going to be, or then, you know, I think there would be a distinct possibility actually that getting off the river would mean the retiring those units.

MR. HICKOK: At Dynegy they're really, there's two plants in play since South Bay, we're planning shutting down in, prior to the (inaudible) schedule.

Morro Bay the prohibition at Morro is primarily on the part of the City of Morro Bay, and we've been down the (inaudible) bridge so it's an ancient plant with a relatively inefficient heat rate so when we went through the CEC permitting process to build or replace a combined (inaudible) power plant there, both dry cooling and wet cooling, we were deemed to be infeasible due to city ordinance as for (inaudible) it would be a very big, very loud structure right in the middle of their town and they're very passionate about not seeing that happen.

At Moss Landing units one and two went through the CEC licensing process. Part of that was looking at viable cooling technologies. Wet cooling would be infeasible due to a lack of sufficient (inaudible) permits. There's nothing remotely close enough to the (inaudible) need to use that (inaudible) technology.

However, I do have enough real estate that dry cooling may be viable. Those (inaudible) cycles are better economic health than my other facilities. It may be technically feasible.

The answer somebody would have to give me is whether I'm going to run into issues with the Coastal Commission (inaudible) dry cooling and power (inaudible) sizable individual (inaudible) so I think that's the (inaudible) challenge for units one and two.

Units six and seven, we haven't in the past taken a close look at retrofitting those units. I think, you know, my intuition is that they're not feasible just given the possibility of real estate between six and seven and units one and two. There's not a lot of land (inaudible) contributes to those units.

They just priced the water flow of the units one and two are so I imagine from an engineering prospective your talking about (inaudible) that are orders a magnitude larger. So we're getting kicked off in the process of doing those engineering studies because we hadn't had the occasion in order to do them in the past. But the jury's out there, but I suspect that unit six and seven in Morro Bay would. We'd most likely retire rather than retrofit.

MR. PENDERGRAFT: Yeah, as we see it I don't know if the answer would be the same for all the facilities, but for all our facilities we don't think it makes sense. Even if we were to get guaranteed cost recovery for the investment I think it's not, it's a sub optimal, environmental and economic solution that, you know, the size of the steam turban on a new combined cycle is roughly one-third of the plant's capacity so the closed cycle cooling you need for a new combined cycle is one-third the size. You know, if you put in some sort of newer peaking technologies you even need less cooling capacity, so I think the path to moving to closed cycle cooling in our mind goes through a re-power more than anything else.

And I think, one comment I just want to interject as we're sort of determining the fate of once through cooling, we do need to mindful of the water supply situation in the state and I think the objective to get to some desal plants built and, you know, one can argue, but I think, you know, the desal facilities ideally it would keep a portion of the once through cooling systems in operation to provide the source water and the dilution needed on the brine discharge. And I think a solution that at least that portion of the circulating water system that the desal plant needs for it dilution should be allowed to be used for power generation or you end up in a situation with probably worse environmental impacts.

If you dedicate the once through cooling system to the desal facility, but you require the power plant to move to closed cycle cooling you are actually adding incremental environmental impacts that you wouldn't otherwise had if you allowed them to both use the same circulating water system.

So I think it's just something we need to be mindful of. I'm sure there, you know, there are people pushing to use alternate technologies for desal as well, but I think we just need to be mindful of the given state's water situation.

MR. VIDAVER: We are running out of time and there's one very important question that needs to be asked. Could I move you off of that perhaps?

MR. PENDERGRAFT: Fine.

MR. VIDAVER: Let's assume that that the process used to eliminate once through cooling and either (inaudible) and replace the (inaudible) facilities or put yourself in the position of greenfield developer we might be looking for another plant to actually compete against ground fill to replace the capacity that would be lost (inaudible) a way from once through cooling. What does that process need to look like from your prospective and I think that the state agencies would say that that process needs to be competitive to provide ground fill and greenfield, (inaudible) equal opportunities to participate and the utility are opposed.

Do you have thoughts on the clarity of the (inaudible) the (inaudible) time you would be contract (inaudible) anything else that would allow you to effectively compete in RFOs and commit capital to either re-power your existing facilities or replace them on-site or investing in greenfield?

Was there a question in there? I don’t know (inaudible) --

MR. LEUZE: I guess the preliminary question would be how you balance a transmission investment against generation investment in the first place and then how granularly do you define the requirement for generation procurement. The ISO did a study it published last November, it was rather frightening in it’s implications. It only looked at transmission investment, but it was enormous requirements and consequences and so somehow it would seem useful to have a framework for how generation and transmission investments are, the tradeoff between those is made.

But obviously clarity, a consistent process, a transparent (inaudible) and a multiyear for research adequacy framework is a good place to start.

MR. BEATTY: Yeah, I'm not sure if I'm answering your question, but I'll through out these thoughts is, you know, I think in our sites our units, and particularly the Delta units that they're actually a very inexpensive source of capacity for the state.

Kind of an analogy I was working on, and it was alluded to earlier, is the idea of, you know, the 25-year-old car. You put some investment into it, you sell the 245-year-old car. But what I would say is for these units really the kind of car we need is one that you maybe drive to the market once a week and maybe even less than that. And so how much money do you want to spend to come up with the kind of car you need to drive to the store once a week. And the analogy I would make is you can buy a new power plant to cover that capacity or you could put some money into these existing units and have a fairly cheap source of capacity.

I think the existing RFO process slants toward the idea of new units. The existing RFO process, as we see it at least, is not really an environment where the refitting of our units is really being taking seriously and I think that if we could create that environment we think we have something to offer the State in terms of cheap capacity. If the State, or if the procurers of electricity aren't interested in that for whatever reason, it's the nature of the characteristic of the plant or whatever it is, then so be it. But if you want a fairly reliable capacity from these plants we think it's a relatively minor amount of investment could provide that solution.

MR. VIDAVER: In the form of (inaudible)?

MR. BEATTY: In the form of refit.

MR. HICKOK: Well I think refitting is a good option for units that are near done in their economic lives, but there are a lot of reasons why I think that at any of these plants you can deliver a re-powered facility with alternative technologies and relatively cheap because you already have so much infrastructure there. In Moss Landing's case I even have an turban building, you know, and just to back him up and (inaudible).

I think my concerns with the procurement processes is, you know, I feel I can compete if it's truly level playing field, but then this isn't truly level, you know. Don't make me sign a ten-year supply contract and compete with a transmission project that has 30 years (inaudible). They're both long-term investments for a merchant plant generator to finance it. If you give me a ten year contract I've got to load so much of my value into that ten years to get it back that by the time you're done it looks like it's an enormously more expensive option.

If you give me the same 30 years to (inaudible) on (inaudible) or even 20 years I can bring my cost down to something that's a lot more of an apples to apples comparison. And then, you know, I would also ask that the analysis been truly comprehensive.

You know, transmission might be a good way to get local reliability concerns met, but it's not necessarily a way to get supply adequacy. And a lot of this issue is not just local reliability concerns, but whether you have enough megawatts.

And a transmission line is great, but if you have a transmission line with no generation at the end you've really bought nothing and I've got assets in the west, I'm not sure where the surplus generation is that you're tapping into in the transmission line so, you know, I would probably spend a lot of time focused on making sure that the evaluation criteria was an equitable one.

MR. PENDERGRAFT: I don't know if I have a whole lot more to add except it's a little bit unclear to me the way the RFOs are (inaudible), right. There's also RFOs and there's new source RFOs and how does a unit replacement or re-power fit into either one of those?

And this, I'm not talking about where we, okay, we shut down a unit today and five years from now we're building a new one, but we want to bid a project that is, you know, constructing a new plant while we're operating the existing plant and then, you know, on the commercial date we flip the switch and we move from the new one to the old one and how do the IOUs look at that.

It's not necessarily incremental additional capacity it's, you know, it's taking some capacity out and replacing it with different capacity. And if that gets any sort of different treatment, you know, any RFO does that, does the number of megawatts that are being procured in that manner, should that influence the amount of megawatts the IOU is allowed to procure or look for, because they're clearly different products. The new (inaudible) greenfield versus a replacement and whether the RFO process should be somewhat adaptive and depending on how much brownfield projects are being selected by the IOU it would sort of differentiate how much they're allowed to procure for.

So that's something I'm still a little unclear on how that would work or how that does work in an RFO process the way they've got them segregated.

MR. ARREDONDO: Just to add again to what's already been said and then try not to make it too lengthy, but just an observation that in the current RFO process the local generations may be significantly under valued. So in the existing market structure I guess adding transparency for what that value might be would be important. The risk would be more at the PUC level an (inaudible) function procurement process.

Also back in 2004, so jumping in our time traveling machine, I was before this Commission and argued for the fully burdened delivered below cost understanding of what generation might cost because at the time we were arguing over generation and it might be in other states that we'd be able to bring in through transmission, and obviously we know what it takes to build transmission in California. It takes a lot of time and a lot of money.

And then I'm trying to understand where that generation was actually going to come from. And then doing an apples to apples comparison versus the (inaudible) brownfield that could be re-powered and could alleviate the greenhouse gas issues, OPC issues and adding flexibility to our RPS goals when you compare those on an apples to apples basis, what would be better for us? Would it not be to re-power at existing sites?

Now we face the local burdens of, you know, please don't do this in my backyard again and where local communities might say, gee now that you're off the once through cooling you should move.

Well we're still very infrastructure dependent. Natural gas is there, transmission is there, so the cost again, the fully burden delivered to customer cost is significantly less by doing these re-powers at the existing sites. Not to mention all of the attributes to grid reliability that Mr. Mansour has to worry about.

MR. VIDAVER: Are there any questions from the (inaudible)?

COMMISSIONER BYRON: Did you, what I was going to suggest, go ahead for another five minutes or so if you've got, did you get through your last question on here?

MR. VIDAVER: Well the final question relates to narrowly targeted RFOs and ensuring that market power can't be exercised. That would really require you to put on (inaudible) developer hat because the (inaudible) your current position. There's one question that was on this list that we didn't deal with directly was whether or not units at their existing facilities could be sort of treated separately and handled differently? Mr. Hickok could probably (inaudible) with respect from Moss Landing. This is going to be pretty easy to do.

MR. BEATTY: Actually that questions a germane (inaudible) it went on earlier today between Mr. Mansour and Mr. Strauss from the PUC. I think there was a bit of confusion about the status of the Portrero unit and I thought I would just address that briefly. Maybe someone has a (inaudible) but brief nonetheless.

As to Portrero unit three we certainly see them as having, or seeing that unit having distinct (inaudible) from our Delta units.

The Trans Bay Cable is being constructed. It's currently targeted to be energized sometime in 2010 from what I understand, in the first half 2010 and that once it's energized and in service that the need for unit three would disappear and at that point the R&R contract would or, you know, sometime shortly thereafter the R&R contract would probably lapse and as a result of that the unit three would be off line. So really in our future planning we don't see unit three operating past 2010.

And then in terms of the Delta units, I've already talked about kind of some of the visions we could see for those units and maybe one other distinguishing factor there is in Pittsburg we actually already have cooling towers in place. They're serving the Pittsburg unit seven and there is a scenario where perhaps those cooling towers are shifted over to units five and six, which tend to be more viable units than Pitt units, so it’s a scenario, it’s something that distinguishes even within the Delta units the Pittsburg plant from the Contra Costa plants.

MR. VIDAVER: Two people that, we have --

MR. PENDERGRAFT: Can more of us answer that question or --

MR. VIDAVER: Oh, go right ahead. Yes.

MR. PENDERGRAFT: Actually, I mean, I think most all of here are tying to, as Mansour and the gentleman from the ISO said, balance a lot of competing priorities here.

Really we’re just trying to look for, in our view, a solution that sort of balances reliability, economics, you know, the environmental air and water and then what’s feasible. But I think by looking at it that way you converge on unique treatment for different units at a similar site. And that’s exactly how we would view it, that we see sort of an ideal solution being one in which a subset of our units are re-powered and replaced with new technology. They provide the bulk of the year-round local reliability services that are necessary. There’s a smaller subset of existing plants that are allowed to continue operating with once through cooling in place. They're only serving a very unique need in the summer. Their impacts are relatively small because of how infrequently they operate.

And we think that's consistent with at least the direction the Supreme Court was going in by using the cost benefit and the original federal rule that actually exempted units with capacity factors under 15 percent from the entrainment standard.

Now we would be willing and open to consider mitigating for any remaining impacts that we had on those units that were serving a very unique need during the summer.

And then there would be a, you know, a further subset of units that would be retired due to the re-powering of the technology that runs, or the units that run the bulk of the time.

And to us that is a solution that we think basically achieves the best overall balance between when you're looking at rate pay or impacts, the actual marine environmental impacts, air and grid reliability.

So we definitely see different treatment for different units at our three different sites. And that would be a sort of an ideal solution for us.

MR. VIDAVER: So are you talking about (inaudible) morality that is not touched at all, but Redondo Beach is? Are you talking about getting rid of once through cooling in Alamitos three and leaving it in place at Redondo Beach because it never runs? Are you talking about 90 percent across your portfolio in the LA basin? Ninety percent reduction in either flow or (inaudible)

MR. PENDERGRAFT: And I am not saying that we would achieve a [sic] overall 90 percent reduction as defined previously. And I'm trying to keep minds open that maybe if you factor in a thorough economic analysis of that environmental policy that maybe we should make some tradeoffs.

And the economic analysis I haven't see is the cost of replacing all of this capacity with new stuff. It's buying new cars for all this stuff, we could have cars that are already paid for and sit in the garage most of the time. Can we afford that?

MR. VIDAVER: I think you have the last word.

COMMISSIONER BYRON: Gentlemen, thank you very much. Very helpful and a wealth of information. I learned a lot of new things here. I think there are things that we're going to look at even in addition to everything else that we're looking currently in working (inaudible) and in particular, you know, giving credit for early action emphasis on mortality over volume metric issues. I think all very good. And this will be a very transparent process.

You will see that the State Resources Control Board will take this on. The State Water Resource Control Board will take this on in a very transparent way. We welcome your continuing involvement and thank you for being here today. We’ll go to the next Panel.

MS. KOROSEC: Yeah. The next Panel will be our utility Panel. This is already (inaudible) again.

MR. MINICK: And I think, while we're setting up, let me just add a few other things. I know Mr. Mansour would like to have some more opportunity for question and interaction, so we'll try and factor that in, here in these last few panels, if not at the end. The concern is at the end that we may be losing a lot of you. And I think I'd say these remarks to both this last panel and the one that's coming up. You know, we're acutely aware of the fact that this all has to be done in terms of the economic interests of the owners and operators of these plants. And that's an important consideration in any rule that's promulgated. We're hoping to do one that's primarily on the basis of reliability. But, I think, as you heard earlier, economic considerations will certainly be considered in all of this. And I certainly got that message, as well, from the last panel. There needs to be a willingness to help resolve these issues as it serves your financial interests as well. So, Dr. Jaske, welcome back.

DR. JASKE: Thank you. So this afternoon we have representatives of four utilities. Mr. Minick with Edison, over here, and his colleague, Mr. Savage, and then Mr. Krausse and Mr. Hatton, with PG&E, Rob Anderson with San Diego, and Mr. Tharp with LADWP. Interesting they're all sitting (inaudible).

MR. MINICK: Good.

DR. JASKE: That's good. Let's focus the first question on these questions that were raised in the last panel on longer run procurement. Particularly procurement that encourages new infrastructure, whether it's new new capacity or replacement capacity. Generally speaking, what options exist to more tightly focus your RFOs to bring forward replacement capacity?

MR. SAVAGE: Thank you, Gordon Savage. Well, we believe in a market based transition as opposed to command and control. And so what we'd like to do in that is recognize the costs of the system and also look at the challenges that, in terms of matching the most plants to the system needs. In our LTPP, as mentioned earlier, we do have two types of RFOs. The new generation RFO and an all-source. The prices for the capacity in the new generation tend to be much higher than the existing generation. And the point of the new generation RFOs is to consent that those new plants to be built. And, in fact, it controls the cost of the all-source article by having sufficient capacity from the system. So what we'd envisioned is RFOs targeted to new generation which we currently have. I want to point out our old RFO that was started in 2006, took just two and a half years to complete in total, we had three phases to it. And the world has moved on significantly from that point. So we'd be looking at targeting changing the specifics of the RFO to match the needs of the system. It wouldn't be simple. I mean, the timing of the article will be difficult. You've got, we'd want to have competitions and a broad field, so you look at that and you look at specifically replacing brownfield plants. We do have in our LTPP a preference to brownfield plants and plants, and repower, and most tend to be once through cooling plants. And also, this issue is far too (inaudible) with (inaudible), given prior reserve issue and current permitting problems.

COMMISSIONER BYRON: Dr. Jaske, are we going to hear from every panel member, because I'm just thinking if we, okay, so that's the SCE response on that one?

DR. JASKE: Yes.

COMMISSIONER BYRON: Thank you.

MR. KRAUSSE: We split them up by numbers so you're kind of confused as this is basically the procurement question, right?

(inaudible)

MR. HATTON: Would you repeat the question, please, thank you.

DR. JASKE: So it's really a narrowing of the first question right down to the issues that the last panel raised about how to modify either the new gen RFOs or the (inaudible) source of the (inaudible) of those.

MR. HATTON: Currently, the longterm RFO process considers offers to develop new facilities, and this process has historically been structured so that offers for facilities using the once through cooling units are not eligible to participate. That's narrowing down that scope. PG&E conducts its longterm RFO process currently consistent with CPUC rulings and policies that are in current operation. As part of the current longterm RFO, PG&E's lead was based upon the 2006 longterm procurement title. And in this current longterm RFO, PG&E has stated its preference to obtain generation from new dispatchable, operationally flexible resources. The bottom line dates no later than May 2015. By obtaining such resources, particularly within the Greater Bay Area, PG&E then can reduce the need for once through cooling units.

DR. JASKE: Rob?

MR. ANDERSON: Rob Anderson, San Diego. And, I think maybe it'll help to kind of put in perspective where San Diego is right now. There were only two once through cooling plants down in San Diego, South Bay and Encina. South Bay, everyone is anticipating will be retired shortly, within the next year or two, hopefully no later than summer (inaudible). So that plant will pretty much take care of itself. The Encina power plant, the NRG that owns that right now, is already going through the CEC licensing. They had proposed to do a repower, a new plant, next to it, at which point they would actually shut down three of the five units at that plant. And so, in a lot of ways, there's the once through cooling issue in San Diego is almost taking care of itself, although I wouldn't say there wasn't some planning and work to make all this happen.

So we may be really down to dealing with two units in San Diego, and what happens to those two units. We have historically, and we will continue, when we've gone out with RFOs, asking for new generation, we've been willing to do longterm contracts, 20, 25 year contracts. There are some concerned owner groups of generators, that they were concerned with 10 year contracts forcing their prices up. We've been willing to do the longer term contracts to help get that price down for our customers. And so, I'm not sure that there's a lot we really need to change going forward.

Our next RFO, we will ask for additional new generation. That may be enough to allow Encina to shut down units four and five. I'm a little hesitant to go out and ask for a product which is a repowering of a once through cooling unit because there is only one party that can get that. And I'm not really sure I've got an all source RFO if there can only be one bidder.

DR. JASKE: Mr. Tharp, is LA in the position of procuring resources from, you know, outside its own fleet, or is your activity almost, essentially restricted to the issue of the operation of your own resources?

MR. THARP: Well, we are currently in the process of acquiring numerous renewable projects and most of those are outside of our service territory and will require transmission. I feel like in some ways I should have been on the previous panel. We do own and operate three facilities with once through cooling that have 2700 megawatts of total capacity, which is about 45% of our peak generating capacity. Our Harbor plant has eight units, with only one using once through cooling. Haines has seven units, five using once through cooling. And Scattergood has three units, with three using once through cooling. Since the 1990s we've gone from 18 units down to nine, so we've cut roughly in half the number of units using once through cooling in our fleet. The question talks about, you know, what kind of options we see, and, obviously, you could shut it down, you could repower it, or you could do some kind of retrofit. Our experience is a strong preference for repowering. We need this power in these locations in our system to support the Port, to support the Airport, to support the West Side of the city, to support the refineries that are in the southern part of our system. These are the only stations that we have that are in these geographical locations, so they're very important to us and we would like to maintain these sites for generation into the future.

DR. JASKE: So do I understand you to be saying that there, there -- although you may not use this terminology, these are essentially local reliability needs for some, if not all, of that capacity?

MR. THARP: That's correct.

DR. JASKE: Thank you. So, let's try to move on to question number 2, come back to you, Mr. Savage. So I know that in the '06 LTPP proceeding with the decision in December '07, that gave allowance for some degree of retirement of ageing plants. Is there actual pursuit of OTC mitigation in the (inaudible) Code of (inaudible) Processes that has been conducted to this point?

MR. SAVAGE: In the current LTPP, no, there is no specific OTC procurement. The only thing that I did mention before was the preference towards the new generation of brownfields and repowers. Yes, it's the quality of the factor in evaluating new generations.

DR. JASKE: PG&E?

MR. HATTON: As I discussed earlier, there's no specific requirement as far as the OTC. Our longterm request for offers are, have been targeted towards new facilities. The process, again, is trying to meet need determination as part of a longterm planning process, and currently our last RFO, or current RFO, is based upon that which is part of the 2006 longterm procurement plan. As part of this process, PG&E has stated that it would like to have new dispatchable operational flexible resources. These are the types of resources which currently provide (inaudible) services that one that are currently used currently produce. We're looking for these, you know, with online dates no later than May 2015, and the hope is that by obtaining new resources that can do many of the same tasks that once through cooling units can do, that, particularly through the Greater Bay Area, PG&E could reduce the need for these once through cooling units.

DR. JASKE: And just in a follow up, when we're talking about Greater Bay Area plants, we're talking about the Pittsburg and Contra Costa plants.

MR. HATTON: Primarily, yes, sort of the geographic area of the Greater Bay Area. The local capacity wide (inaudible) area.

DR. JASKE: Is there anything more you want to add on behalf of San Diego, for this second question?

MR. ANDERSON: Probably not a lot other than I'm not sure modify is a good word. I mean, we've been kind of looking at this issue, we knew these plants are getting older. There's kind of been a desire for the city to get (inaudible) shut down. So, I mean, our procurement over the last, probably four or five years, our efforts to get the Sunrise Power (inaudible) has all been driven with a recognition that these older plants have a minimum number of years left on them. So when you say that the once through cooling issue we knew would be (inaudible) factor, it might be great to say that given some (inaudible) panel. But we recognize these are older plants, their life is coming to an end. We need to find a way to get our grid up and running, given those plants will retire sometime.

DR. JASKE: I think maybe question 3 would be helpful here. Although we haven't been very specific, you know, as in my opening presentation this morning, you know, sort of outlined (inaudible) South Bay as an example where there's pretty well understood timeframe in which that plant might no longer be necessary. You know, were there to be more generally, you know, that kind of understanding about the existing (inaudible) in our various service areas. I urge you to take advantage of that knowledge and, you know, and sort of contracting with plants, you know, up to that point and not contracting with them, you know, beyond that point, and, you know, in effect use the procurement process to help cement that plan into reality.

MR. SAVAGE: Just to clarify, are you saying that there would be a plan for the plant shutting down on a date certain and therefore we wouldn't contract with that plant further on?

DR. JASKE: Let's just say, in a hypothetical way, yes.

MR. SAVAGE: Yeah, well, we wouldn't want to contract at the point where they're (inaudible) retiring their plant. But it's clear our LTPP sets out our timeline under the contract (inaudible) it's currently 59 months and it has to start within 12 months, that contract. And so that puts a time limit on how far out we can contract. And part of our due diligence, if they came and told us that they had retirement plans, that would come up in the negotiations to the contract.

MR. HATTON: I guess similar to what Edison has said, you know, the possibility exists that we could target, or we could have contracts with a plant as (inaudible) also stated that our current longterm planning procurement allows for sort of one to five year contracts. PG&E currently believes that existing OTC facilities are eligible to participate in this intermediate term or (inaudible) process, that's what PG&E calls it, and for the 2009 cycle, for example, PG&E's procuring for power out through the 2013, to the extent that any plant would fall into that particular timeframe. Of course that would be eligible to participate as policies and regulations change, PG&E could be prepared to make changes in its (inaudible) intermediate (inaudible) process, for example, to the extend the years or (inaudible).

MR. ANDERSON: I want to turn this question around a little bit, given that San Diego's a pretty constrained service area. And to some extent, until new generation is built (inaudible) gets built, basically where in the current situation where everyone's through cooling plant is needed for everyone to meet their local RA obligations. So really, it isn't that I need to know so much about the once through cooling regulation, but, for the most part, these plants are going to have to be relied upon (inaudible). I think even if we launched an RFO today, we're probably talking about 14 or 15 before that (inaudible) plant would ever get built. So I think we're going to be relying on some of these units out to that timeframe for reliability reasons, much less for the regulations. I'm not sure the regulations will really drive us to need to change anything near term.

DR. JASKE: Okay. That actually is a --

MR. MANSOUR: Mr. Jaske, if I can just, if I can just make sure that some points are very clear to all of us. At least the heat waves of both 2006 and 2007, every single generator was online and every single generator was needed, plus all the (inaudible) were loaded. That's a fact. Now is there any debate that every single generator in the system today is needed from a consistent capacity point of view.

DR. JASKE: You can correct me (inaudible) I don't think all generators have contracts with us for resource adequacy purposes. So --

MR. MANSOUR: (inaudible) needed.

MR. MINICK: Well, a lot has changed since 2006 and 2007. Our loads have dropped significantly and we have a lot more load management and energy efficiency programs in place. So I can't say with certainty that I absolutely have to have all plants right now. Certainly, I needed them then.

MR. MANSOUR: So, we can then, what? Like we don't need?

MR. MINICK: Hypothetically, maybe a 1000 megawatts or something, we haven't, I haven't gone back and looked at the exact numbers. But if I took a look at the summer right now, I think the ISO has, it's one of the better summers for us in the last (inaudible).

MR. MANSOUR: Oh, because of the recession, because of the recession.

MR. MINICK: Yeah, right (inaudible).

MR. MANSOUR: (inaudible) system forever, that would be fine.

MR. MINICK: But, the question was do I need them right now, and things change in the future. I am a planner, for a long, long time at Edison. Things are going to change over the future, we are pushing energy efficiency. We are pushing demand side programs. We are pushing the renewables. And so, in time, based on pure capacity, there might be a reason not to need all these plants. But I have to look behind the grid, that's your main responsibility, and I'm very concerned about that in some regards. We have to have the ability to integrate new renewables and we have to have the ability to keep the voltage up and use inertia and all kinds of operating criteria. And that's where it gets a little more tricky, okay. A lot of these plants provide services because our system was built from the fifties on around a grid that's basically local right now. And to try to import all the power we need to run the grid is a daunting task. If your engineers looked at it, that's a five billion dollar expenditure and I don't think they solved all the issues. They did see that for five billion they could try to import power. I'm not sure they solved all the inertia issues and some other issues under all operating conditions. I think they sort of said we got more work to do.

MR. MANSOUR: Yeah, I just want to add that (inaudible) we are actually in peak times, we still get 20-25% from out of state, which is a quantity that I don't know whether we can depend on it with any reality. Then your 1000 megawatts, I don't know if we can just (inaudible) 1000 megawatt, knowing that someone else, somewhere else will build it for us and we'll always be able to get it. The second question is on integration on renewables. At least all (inaudible) at our lab, I don't know if anyone has done a study to contradict that, the capability of the current fleet for regulation, for reserve, for everything, is needed to support those 20%, at least, if not more, much more, at 33%. Now that is not a service that necessarily you utilities can contract for, right? So what do you suggest? Who is to actually make sure to keep those facilities in service to provide those services that you do not contract for, but it is needed for the system?

MR. MINICK: I think we would be responsible for our ancillary services for our load. At least, I'm not an (inaudible) expert, but I think that's our obligation. Regarding studies of the future, I know your people and I are going to start working on a 33% renewable integration analysis and I've read your old analysis. I know it pretty well. I can't say with the way things change in the future, the future's going to be radically different. We're going to have electric vehicles, we're going to have more solar cells on roofs, we're going to have changes in the way the grid is built out. Then I will definitely need all those resources in the future. I think it's a reasonable assumption for the time being because of the intermittency of some future plants and resources, like wind. Wind is a little scary when it doesn't show up at the time of the peak and things like that. I can't say with certainty I will always need this level of these kinds of resources. We have done some studies. We have looked at new technology and how we've built out the grid. We do like Elements 100 technology for peakers. We have contracts with some, or even signed the contracts. We can't build them because of the (inaudible) issues right now. So if we could have more peakers on our system, if we could have more hydro pump loads, or more compressed air energy storage, or more batteries, there may be a way to build the grid differently than we have it right now. Again, I'm not saying you shouldn't have them for the time being. The future is very difficult to predict and very difficult to plan for.

MR. MANSOUR: So what do you suggest Mr. Bishop? Say you're going to need 2000 megawatts, you going to shut them down, or what do you suggest for him? Because I'm talking to them talking to you, I'm suggesting to you. What do you suggest then? Like we don't need it all, take, you know, some amount of it?

MR. SAVAGE: I'd go back to the previous panel, I think they mentioned about looking rationally at the overall system. Like let's look at the total cost, the total environmental benefits, both air and water, and make sure we're doing the best things for society as a whole. I mean, looking at, specifically just the water impacts, the ocean impacts (inaudible) is starting the impact on air and land use. I think we get to a suboptimal solution.

DR. JASKE: Let's try converting Mr. Mansour's question into a very specific one. The ISO's current studies for PG&E say the Greater Bay Area has a surplus. ND26 overall has a surplus, will have a surplus for at least a number of years. Gateway just came online, it's essentially next door to Contra Costa. Does that mean that one of the Contra Costa units essentially could be shut down tomorrow, barring any, you know, contract that exists? Because it's really not "needed" for reliability and achieve some environmental benefit.

MR. HATTON: Well, I guess there's, in my mind there's two types of reliability. There is system reliability and then there might be local reliability or reliability for specific ancillary services. I think with me, and what you've talked about, as far as looking at the Greater Bay Area, or the ND15 or ZP26, is primarily looking, or counting megawatts, versus really system reliability (inaudible). If one dives down and looks at specifically a local capacity constraint, I think there's some studies that we've done that say no, there are not an excess of potential resources. And I think we'll be getting to a question later, which I can address some of a specific study when we talk about the transmission system improvements that might allow existing facilities to be retired.

DR. JASKE: Okay. Maybe before we leave this set of questions and move on, Mr. Tharp, or for LADWP, would you, you made a point that the plants that LADWP presently has, in the Harbor and Scattergood areas, you know, are needed. Is all the existing level of capacity that's at those general facilities needed? Or is it that some capacity is needed at those three locations?

MR. THARP: Oh, I think some capacity is needed in all those locations. Some of the slides that Mr. Vidaver showed indicated at least two of those plants had units running 365 days a year. And so, I mean, we need generation in those locations. The type of generation, and what it uses for cooling, may change, but we need generation in those locations.

DR. JASKE: And are there contingencies that LA is guarding against that are, you know, observable in, you know, the particular snapshot year of operating history that he was showing would imply a value for that capacity that sort of goes beyond 2008 or 2007 operating history that he was showing?

MR. SAVAGE: Well, I think to kind of use one of the things that Mr. Mansour said, during the summers in '06, '07 and '08, there were weeks and months were every unit was on in all of our system.

DR. JASKE: Let's turn to question 4 and this, of course, utilities (inaudible) table, do still own some facilities, so for those that you own and operate, what is your commitment or your planning for reducing or eliminating OTC?

MR. SAVAGE: We're down to one plant, which is SONGS, and we've done a number of technical upgrades to reduce the environmental damage from that plant. As well as three environment projects to help offset the effects of the plant, including wetlands, 150 acres wetlands planned near Carlsbad, five million dollars towards Hubs White Sea Bass Hatchery, which (inaudible) shut down plant now from time to time to save those fish, and the Mueller North Reef project, which is an artificial giant kelp (inaudible) note the California CPC, in its decision, fully believes that these projects, along with the technical upgrades, fully offset the all marine impacts from SONGS.

DR. JASKE: So do you see (inaudible) made that decision?

MR. SAVAGE: Yes, it's the Coastal Commission.

MR. MINICK: Oh, it was the Coastal Commission, I'm sorry. Do you have the citation?

MR. SAVAGE: No, but I can Google and get it for you.

MR. MINICK: Just, in your written comments, if you'd please provide a citation.

MR. KRAUSSE: Dr. Jaske, Mark Krausse, PG&E, I just quickly want to say how much we appreciate that the agencies are lending your expertise (inaudible) to our Board. As I think has been mentioned mostly today these points were all covered, that we've retired Humboldt, or will be by the time 2010, we expect to see once through cooling eliminated there. The decision to dry cool the (inaudible) Generating Station. The retirement of Hunters Point and finally, most recently, Colusa (inaudible) dry cooled project, approved by the Commission. PG&E will, like Edison, have just one once through cooled project by the end of 2010, that is the nuclear plant. I think that's the, I'm glad that we've gotten to that because, you know, this is the parenthetical of this whole OTC discussion is what do we do about the nuclear plants. Just going into the impact issue, Diablo Canyon was built and designed to avoid any (inaudible). The cove, the way that it's built, is onshore (inaudible) offshore, has as the Central Coast Water Quality Board says, virtually no impingement, and the entrainment, we, through studies that the plant has done since before construction. We started studying, it's the largest database of biological studies that we are aware of, certainly on the west coast, we show about a 10% entrainment of (inaudible) those rocky reef species, but no demonstration of adult population impacts. And I believe even the Water Board's expert panel essentially came to that same point of view. That we know that are eggs and larva being entrained. And I raise this not to, I know we've been admonished not to talk about (inaudible) policy, it's really to put it in the context of, if you juxtapose the impact on (inaudible) in a moment here, California's environment, its air quality, its goal of meeting EB32 mandate. If you juxtapose (inaudible) impact, I think that's where we (inaudible). So PG&E has evaluated all current screening technologies for many years and most recently it has been suggested by Water Board staff and others, a cylindrical wedge water screen. So that's something we looked at very seriously, but given the Central Coast climate and kelp and other things that already take occasionally a (inaudible) trip, that would be infeasible. We've done extensive study of retrofit at Diablo Canyon and we hope to share before the next workshop with all the energy agencies (inaudible) that shows substantial environmental impact from retrofit. And I guess that's where, you know, the previous panel on permitting wanted to hear a little more meaningful discussion about permitting retrofit. But of course with the gas plants, the issue is repower. I would have loved to have heard, and I'm sorry, I would have (inaudible) question period, whether the Coastal Commission would permit, I believe we talked about 120 60x60x60 foot cooling towers that would take a huge footprint out of Diablo Canyon to mitigate those other impacts, enormous excavation of over two million cubic yards of the adjacent (inaudible) hills. It was found by both the Ocean Protection Council (inaudible) Study and our own study, that dry cooling is not feasible at Diablo Canyon, but close cycle web cooling would be. And some of the other impacts of that would be some, I believe it's seven million tons, 15 million pounds per year of salt deposits across the Irish Hills there and would cause (inaudible) on the lines also (inaudible). And, essentially, I mean, I can give you the long list. I'll shorten it very quickly, cost impact on the order of 4 to 4.5 billion dollars to retrofit. So we're in that, you know, air quality, rock and water quality hard place. Along with SONGS, which offers about seven million metric tons per year (inaudible) benefit. And you just reverse that if you ask us to retrofit in one year of down time, the two plants would cost the state about 14 million metric tons of greenhouse gas emission. And that's, of course, assuming the most conservative, the cleanest gas fired back-up right now. We don't anticipate geothermal (inaudible). Just wanted to get that out on the table.

DR. JASKE: In previous response, as (inaudible) referred to (inaudible) if there's been a termination for Diablo Canyon?

MR. KRAUSSE: No, but PG&E was scheduled, I believe, in 2005 or 6, to enter into an agreement that we had negotiated and a Central Coast Water Board staff had approved for many millions of dollars in (inaudible) mitigation. But because of the pending rule and the Riverkeeper litigation, that was put on hold by the Water Board, they actually did not vote on the policy as I understand it, or voted to reject it, the settlement. So we have other mitigation and in fact, I was talking about the Water Board. For the Coastal Commission, yes, we've done other mitigation, in both the trails we've conveyed easements, (inaudible) conservations (inaudible).

DR. JASKE: Okay, in our remaining time I think we need to shoot for the question of transmission systems improvement (inaudible). Transmission system upgrades are at least partial substitution for (inaudible). Care to offer some thoughts?

MR. MINICK: Well (inaudible) I'm not a transmission (inaudible), but I've been at Edison for 35 years doing generation and resource planning for 25 of those 35 years. There are various types of transmission system modification and enhancements that might allow some retirement of existing plants and still meet the applicable reliability and operational considerations that the ISO, I'm sure, is worried about just like us. But transmission studies are highly dependent upon the assumptions used for the analysis and there's not a single specific fix or modification that would work for all possible resource expansions in the future. This is quite complex. We have to look at different scenarios and those scenarios include load considerations, growth, new load, new electric loads, new distributive generation, new resources, the types and locations of these resources, whether they have inertia, whether they're out of the basin, whether they're in the basin. It is a very, very complex thing to do. So, no, there isn't one magic bullet that says fix it like this and it's all solved. We have to work with other utilities when we do transmission plans, with the ISO when we do transmission plans. We have to take a look at these scenarios into the future to see what's the optimum mix. And I think many of the panelists today have said there may be better fixes and optimal fixes, what's the cost and the reliability considerations of all these fixes? It's not something that I can do overnight. I don't think the ISO can do it overnight. I don't think any environmentalist can do it overnight. We're going to all have to work together to see what is the best optimum fix for this state to keep the lights on and try to mitigate a lot of these environmental concerns.

DR. JASKE: Let me ask PG&E if you could just answer (inaudible) follow up?

MR. HATTON: Sure. You know, Mark brings up a lot of good points. It is a very complex issue and PG&E believes that a system reliability study should (inaudible) regarding (inaudible) and perhaps the (inaudible) ISOs and (inaudible) study these alternatives (inaudible) planning process. PG&E believes that it's critical to conduct a study of these alternatives expeditiously because any delay could limit the number of options potentially available by 2015 to the (inaudible) transition away from some of these (inaudible). In analyzing a process to (inaudible) units, a key area for PG&E is the (inaudible). It's a local capacity reliability area that contains a significant number of OTC units. (inaudible) area transmission upgrades are likely to (inaudible) of any longterm process to phase out the OTC facilities. These infrastructure improvements could include both additional ability to move power over power over lines as well as the (inaudible) support devices. It is likely that some of these improvements could be retrofitted from existing facilities. But others may require the need to put up new lines or new substations or other transmission devices. In addition, as Mark says, it needs to take into account other uses of these facilities. These facilities are used for the Greater Bay Area to solve a Greater Bay Area problem, but they're also used, for example, as perhaps (inaudible) additional ancillary services to support additional renewables and we'd take that into account (inaudible) the services that these resources currently provide. PG&E has commissioned a study of OTC (inaudible) scenarios which was conducted by Quantum Technology, to look at this issue and some of the highlights of findings that they had come up with were that retiring generation in the Greater Bay Area without replacing that generation would require transmission system reinforcement, possibly new transmission lines and an increase in (inaudible) system will be able to support devices within the Greater Bay Area. And since the Greater Bay Area system is already heavily compensated, numerous voltage support devices will not alleviate all constraints that would be created by retirement of these units in the area. So therefore, new, either rebuilt, or repowered, or new generation, within the Greater Bay Area would be essential to maintain the proposed transmission system.

DR. JASKE: Is this study by Quantum that you mentioned publicly available?

MR. HATTON: Yes it is.

DR. JASKE: Okay, if you could give me a citation please, I'd appreciate it. Mr. Anderson?

MR. ANDERSON: On our transmission (inaudible) and I will also. (inaudible) being a planner, being around, you know, this industry a long time, to me there's no doubt we're going to need more transmission and it's not just going to be that will make the (inaudible) goal issue. As we get more and more renewables on the grid, the transmission to get the renewables here, I think the ISO is going to find the more transmission it has, it will be able to deal with the swings better, will be able to deal with the ramps better. So I think transmission is going to be part of our longterm solution. I'm not sure, though, it's going to be targeted just (inaudible). The other issue there is, and we've just been through it, it's probably 10 years from the time you start your planning until you get a major line up. And if people (inaudible) before that 10 year period, I'm not sure transmission is going to be (inaudible).

DR. JASKE: You indicated earlier that zoned project additions could allow the retirement of at least some of the (inaudible). You see a solution for the remainder of the Encina facility?

MR. ANDERSON: I think that will come through new additions in the San Diego area.

DR. JASKE: New gen?

MR. ANDERSON: New gen, yeah. Yeah, this question was a little bit remote gen, I think we're going to do what we can to get it, our replacement gen still (inaudible) the load center. Because I think we're going to need it there, given all the renewable power that we're trying to bring in. So I (inaudible) the fossil that I can maybe pick where it gets located a little bit better, closer to load, and fill up my transmission lines with fossil.

COMMISSIONER BRYON: Excuse me, follow up, how do you, how do you pick where it's going to be located?

MR. ANDERSON: It's actually the last panel that basically picks and they (inaudible).

DR. JASKE: Mr. Tharp, can you give us any idea of the extent to which transmission system changes offer any opportunity for OTC reduction in Los Angeles?

MR. THARP: I don't think it offers much opportunity for reducing the need for generation in the southern part of our system. We are doing -- we have several transmission upgrade projects in the works right now. I think everybody knows building transmission, getting it sited and permitted is very difficult. We have three or four of those that are working (inaudible) import capacity for renewables. We're also doing some strengthening of our central belt lines to our generating stations, but even with those strengthening projects, it won't eliminate the need for generation in that area into our system.

DR. JASKE: Over the decades, as Southern California has become increasingly urbanized, is it the case that you were sort of locked into the transmission system, you know, in your actual service area as it exists today and there's little if anything that can be done to change that?

MR. THARP: As a general statement that's true. I mean, there are some small things we could do, but much of our transmission has been built up, there's been things built around it and we are, in essence, kind of blocked with what we have.

DR. JASKE: So would it be going to far to say that it's essentially infeasible to build transmission that would, over to the western area, where Scattergood is, that would allow Scattergood to not operate, or operate perhaps only in some very rare contingency?

MR. THARP: I would think that would be very difficult.

DR. JASKE: Is it simply difficulty of developing transmission in a highly urbanized area like that or are there particular permitting issues of doing so, you know, just where the right of way wouldn't actually be in the city of Los Angeles. Are there particular permitting issues or complications of that later sort?

MR. THARP: I think so, yes.

DR. JASKE: Do either of you gentlemen from Edison have any comments on that particular side of the problem?

MR. MINICK: Well, certainly, we (inaudible) do transmission studies all the time and the ISO does local capacity requirement studies to say what we need every year, and the number changes with the kinds and types of resources that we have. We've also, we have to look out for how the grid might develop in the future by importing renewables. We do have plans to upgrade some of our facilities, but as everybody here has said, if I'm going to increase my backbone in the LA basin, which is the main, my main transmission system and convert 220s to 500s, citing and licensing that is extremely difficult. It might be possible, but I'm not the expert to say it is possible. We would have to do that. If you're going to replace generation along the coast you're going to have to increase the voltage on your backbone and taking (inaudible) more power. And as we've said, it's probably going to take 10 years to do that, so even if it was possible, and, again, I can't say whether it is or isn't a possibility. The ISO's looked at it and we've looked at it. It's going to require quite a bit of time, and so the Water Resources Board (inaudible) flexible thing. Let us look at it, let us recommend it, let's look at the new resources to try to do it. It's going to take some time to do it.

DR. JASKE: Let me just try to press you one more step and are there areas of coordination between the Edison system as it's adjacent to LADWP that offer any opportunity here, aside from all the jurisdictional issues that are obvious?

MR. MINICK: I don't, LADWP can answer for themselves. I haven't studied any more interconnections to your grid to see if we could beef it up together. We have a joint operating agreement that we honor. We have areas where we connect the two systems. I don't know of any studies recently that we've looked at trying to prop up voltages on the two systems.

COMMISSIONER BRYON: They don't talk much. If I may, just maybe one or two follow on questions. This is very helpful. I think we're all in agreement. We have a formidable problem ahead of us here. But given Mr. Anderson's comment earlier about he doesn't prefer to give out RFPs for one respondent and, of course, Mr. Krausse indicated that PG&E's taken care of most of their problems. The only real issue in the long run is the nuclear unit. So maybe I'm directing this question to Southern California, but is there, are there changes that we can make that, I mean, thinking outside the box a bit, so the procurement process that might be able to address once through cooling.

MR. MINICK: Well, again, I think Gordon can answer most of it. We have signed some solicitations for some new projects that might help shut down existing plant. But there are right now locked up in litigation at ROCPM10.

MR. SAVAGE: Yeah, that's essentially, I think we need a solution to the PM10 if we're going to build anything more in the basin. I know the gentleman from South Coast is here as well, he, I know they're working and trying to make it so you can use existing plants, the offset from the plants to be able to build. I know he's working on this and it's going to take about a year or so to have that fixed. And once we have that, then, we'll have a better app forward. Right now there's an awful lot in the air. We have (inaudible) is an issue, we have

PM10, and we've got direct access that we're looking at and we're also looking at (inaudible) integrating maybe 33% renewable. It makes it very hard to predict, (inaudible), let's do an RFO that's going to take us 18 months and then 18 months to three years, whatever it may be, and then once we get through that, then it's two to three years to build the project. It's very hard to make choices right now.

COMMISSIONER BRYON: Right, but I hope you'll agree that this is one of the things that we want to explore a little bit further as to how we might be able to use the procurement process proactively here to help address this issue. Mr. Tharp, forgive me if I'm, if I'm asking you to repeat something again, but I just wasn't clear in terms of clearly the approach, the rule that the State Water Resource Control Board is going to promulgate will apply across the board here, you've got some units that are in harms way, so to speak. Is LADWP's plan to repower those units?

MR. THARP: As of right now we've got plans announced, I mean, we've done two repowerings in the past, we have two more that are on the horizon and that are caught up in the PM10 issue, and that's all we have on, that we can see on the horizon. Certainly you can look forward and say, well, probably beyond 2015 we would need to do additional repowerings, but our system needs sort of go out for these two repowerings, one at Aines and one at Scattergood.

COMMISSIONER BRYON: Okay. Mr. Jaske, any other questions?

DR. JASKE: Not in the (inaudible).

COMMISSIONER BRYON: You've kept, put us back on time. Gentlemen, thank you very much for being here. This is extremely helpful and I'll reserve, I hope you'll be here for the closing remarks because I think Mr. Mansour and I both have some conclusions to draw about all the things we've learned today. But, again, thank you very much, we're going to need your continued help.

COMMISSIONER BYRON: Welcome, everyone. I see that we still have Dr. Jaske moderating our panel. I’m glad to see that. And, Dr. Jaske, I’ll hope you’ll introduce all these people to us.

DR. JASKE: Yes, I will. And we have a little bit of a complication. One our panelists, the representative from NRDC, is not yet here, and Mr. Geever actually has a plane flight. He needs to leave at 4:15, so I’m wondering whether in this particular instance if I work to essentially have each of the panelists run through the questions, you know, individually on behalf of their organization. And then to the extent that the NRDC person comes, we'll be able to do that.

So, Mr. Geever, maybe we'll just start with you and if you could take a look at the questions attached to the agenda and then I may some -- and give your responses, and I may have some follow up for you as we go along.

MR. GEEVER: Thanks for accommodating my flight schedule there. I appreciate it.

Yeah, well, I'll tell you, I've prepared a long list of responses to these questions before I got here. And now that I've listened to the presentations, so I'm going to try and wing these.

I actually think that number four is the one that perplexes me the most after having listened to the other panelists. It's that, you know, the question of is delay actually going to help implement this OTC policy or not. The probability that once a policy is developed it will be actually implemented. Well, look, I guess at the risk of oversimplifying this, developing a policy that won't be implemented is kind of pointless. So if it won't do that, then there's no point in delay.

It sounded this morning like CA ISO had some amendments that they were going to offer that I'm not sure it necessarily meant delays in the policy but some changes to the policy that would -- that would help resolve some of these complications that you're dealing with.

I'm not going to speak for anybody but Surfrider Foundation, but we're certainly open to solutions, any kind of creative solutions that resolve multiple problems at the same time. But without having seen the recommendations they're making, it's impossible to say whether we will support that or not.

DR. JASKE: Well, let me in looking at these questions now again, I can see they probably could have been tightened up a little bit.

One interpretation of the first sentence of question four was the following: Previously, the Water Board proposed 2015 as the compliance date for the low capacity fossil plants converted into 2016, 2017, 2018, you know, whatever, some set of dates of that sort, but those dates were compatible with the overall energy agency planning process. Is that the kind of tradeoff that could make sense to your organization?

MR. GEEVER: I'm sorry. If they were compatible with?

DR. JASKE: Is that a change relative to the Water Board's previous 2015 compliance date that you could live with? With the implication being that 2015 is sort of an artificial date that wouldn't necessarily happen in the real world. It might be on someone's rule book, but you know as the date came along and the replacement infrastructure wasn't, you know, ready, then presumably there would be a strong clamor for that compliance date to be pushed back.

Whereas, if we go through this process and we try to do the advanced planning and identify a compliance date for planner plans that does seems compatible with planning and procurements and construction timelines that there might be more viability to those date than just picking 2015 out of the air. And given that tradeoff, is that something that your organization could support?

MR. GEEVER: Excuse me. I guess I wouldn't characterize 2015 as picking a date out of the air. You know there was one study conducted for the Ocean Protection Council that seemed to suggest that with the proper planning that that target date was doable. So without any other studies to compare it to suggesting that there are some benefits to prolonging that, I question the plan. Just like I tried to say before, you know, we're open to looking at those, but they haven't been offered.

Look, I'm over coastal and ocean issues, but it doesn't mean that I'm not concerned about air quality. I also breathe, so you know, I'd also like to make sure that the Clean Air Act is enforced as well.

DR. JASKE: So maybe that's a good segue into the first question --

COMMISSIONER BYRON: Right.

DR. JASKE: -- because the first question is the basic tradeoff between doing something for OTC versus the whole constellation of air, land use, visual consequences of other replacement infrastructure.

MR. GEEVER: Yeah. You know I've heard some of the panelists talk about, you know, doing this detailed cost benefit analysis and making sure that we get the greatest societal benefits from whatever policy. From years of working on marine issues and marine life issues, management of marine life, we don't know enough about marine life to talk to relations of -- It's entirely outside of our realm of capabilities. You can't monetize marine ecosystem impacts like that.

So, you know, as much as I -- I guess I had a little bit of training in economics and just enough to get myself into trouble but also enough to suggest that that's not really entirely doable at this point. And tradeoffs seems to imply that, again I don't mean to put words in your mouth, but, you know, are we going to fully enforce the Clean Water Act or are we going to fully enforce the Clean Air Act? Well, we're going to fully enforce both of them. How we do that, you know, if CA ISO has a plan that allows us a way to that, like I said, we're waiting to see it.

I'll make this point. The Clean Air Act or the Clean Water Act in 316(b) was passed 45 years ago. And when they passed it 45 years ago, once-through cooling was the common practice at coastal power plants. As much as I'm sitting here today, the Congress did not intend for once-through cooling to be the standard practice four decades later. That's just, you know, as frustration here.

Look, you've got to understand that we've been waiting an awful long time for this law to be enforced a year here or there. It's the desire of the environmental community, but it's more important that you set a deadline that we're going to stick to and that we're going to fully enforce this law finally.

And if I can, I'll add one thing and one of the panelists from the generators suggested that one of the conditions, not to make even this more complicated, but that, you know, there's co-relocated desal proposals out there on the table now. You know, we're running out of water and we have to take that into consideration.

Let me tell you just a couple of facts about the co-located desal facility and how that relates to our OTC policy and grid reliability and all these other kinds of targets that we're trying to meet. This is the most energy-demanding source of water you could ever devise.

It's 40 percent more energy demanding than pumping water from Sacramento to San Diego to allow us to run that plant and so on up and down coast, and each one of them is expandable. That's an additional demand on a grid that you're already trying to figure out to, you know, make more reliable. This is not the answer to our water problems. This compounds everything that we know about.

The water that they need for that plant is actually more water than what they're withdrawing to cool the power plant at this time. It's 11 percent more, so you're adding 40 percent to the most energy-demanding source of water and you're adding 11 percent more water intake to run the desal facility. You've undermined all of our policies.

To get back to your question number three, how does your organization propose to participate in efforts to remove the current inability to locate new power plants within most of Los Angeles Basin? I don't know. You know, it's really an unfortunate circumstance that, you know, NRG wants to build a high-efficiency plant there. And for some malfunction at the Air Quality Management District, that thing is being held up. You know, I think that those proposals are the kind of things we should be looking at, and it's an unfortunate set of circumstances that that project is being stalled.

So I’m open to suggestions of how we can help with that project moving forward.

DR. JASKE: There’s a considerable coalition of groups who have been pursuing OTC. Can you imagine if some or all of those groups, you know, somehow or other participating in broader environmental issues, you know, like the particular instance of South Coast’s, you know, air credit that you just mentioned and somehow or other speaking from an overall environmental perspective?

MR. GEEVER: I’m disappointed that, you know, our NRDC representative didn’t get here on time to be a part of this panel because I was looking forward to his recommendations on creative solutions to this. And because I don’t work in air quality, I don’t have those kind of, you know, have recommendations for you myself.

But like I said, I’m not willing to sacrifice full enforcement of one law for full enforcement of another. But you know, this is a time -- This is a time to start thinking creatively. It’s a time to start thinking creatively about water solutions and all sorts of greenhouse gas emission reduction and adaptation. Everything is on the table.

DR. JASKE: Thank you for stating that. Question number two, which was the last one on the list, and that is, of course, a non-power plant solution to managing our electricity load situation is more energy efficiency, more renewables that don't have any air or water consequences at all, but we're already apparently planning on relying upon those in unprecedented levels. The ARB GHG scoping plan calls for major increases in all those.

Do you foresee anything more than what's already being planned in the level in the ARB scoping plan?

MR. GEEVER: Well, I can tell you within the limited scope of the stuff that I work on, I mean I tell people that, you know, now people wonder why is the Surfrider Foundation is working on water supply stuff. And I tell them I got sucked into it through a cooling water intake, and the reason why is because of this idea of using these intakes for desal. So not wanting to be the naysayer to a new water supply, we've been looking at a lot of water supply alternatives.

And I can tell you that it just shocks me that it was surprising to find out that 20 percent the state's energy usage is about moving water around. And if there's a target for energy conservation and greenhouse gas reduction, it's water. That's a big target that we can't overlook and to come up with solutions that are energy demanding than what we're doing now seems like backwards thinking to me. But there's a lot of conservation that can be had -- energy conservation that we can gain through smarter water management, you know, adding the imbedded energy component into our water management portfolios so that's one thing.

And maybe I'll just throw this in anecdotally because it was a thought that I had with trying to walk in the door this morning was that now I have PV panels on my roof. They don't cover my roof. I calculated them to supply what energy every year or maybe a little bit goes back into the grid. I was considering rather than rebates for roof photovoltaics that, you know, the utilities get into the business of installing those things.

Just imagine a system where, you know, a homeowner was offered free PV cells for their roof, and it would be more than they could use, and that they would have to agree that the excess would go back into the grid. We're talking about putting photovoltaics where there's no concern about the habitat in the desert or any kind of environment impacts. These are rooftops. It's not habitat for anything. The problem of using energy and undermining our efforts in conservation, you only would be allowed a certain amount of free energy from those photocells for your house. Anything over that, you'd have to pay for just with photovoltaic cells.

I haven't thought this thing through, but I think there’s a lot of creative ways to get renewables out there and get them out there really quickly. But the one thing I do know is water. There’s a lot of energy that we can save in rethinking our water management portfolios.

DR. JASKE: Thank you. Thank you for agreeing to sort of go solo here.

MR. GEEVER: Well, thank you for allowing me that. I’d be glad to answer any questions.

COMMISSIONER BYRON: None. Okay. Mr. Geever, thank you. I think we got your frustration. It’s been a long time. You want to see a rule implemented. And of course, what we’re doing here today is to try to understand the complexities of how to go about a reliability-based rule so that the electricity doesn’t go off in the meantime. But this will, I understand, according to the State Water Resources Control Board, will be promulgated this year.

MR. GEEVER: Like I say, I appreciate the effort that you’re going through here. I want to, you know, breathe clean air. I like going home and turning on a switch and having my light bulbs come on as much as the next guy, and so, you know, grid reliability is important. I wouldn’t discount it, you know. Thank you very much.

COMMISSIONER BYRON: Thank you, sir.

DR. JASKE: Okay. I observed to myself

somewhere along the way I failed to introduce the remainder of the Panel before I started quizzing Mr. Geever. So our other panelists are Deborah Sivas with Stanford Environmental Law Clinic, Angela Haren, California Coastkeeper Alliance, and also Bill Powers from that same group. Special thanks to Angela for helping me identify these folks and arrange that they come here today.

So who would like to go next?

MS. SIVAS: Are we just going to go in order? Are we going to go back to --

MS. HAREN: Whatever you prefer. I unfortunately received a message from the NRDC staff that they're stuck in an Assembly hearing, so I'm not sure that waiting that he'll be able to make it either way, so it's up to you. We could go in whichever order you prefer.

DR. JASKE: Well, then why don't we just continue. I actually prefer the crossways, so let's now go to question one, and we'll just work our way across the table.

So what about this question of tradeoff between OTC mitigation and potential increase in adverse consequence from new generation or new transmission?

MS. SIVAS: So I'll start. So just to let you know, I teach at Stanford Law School, and the Clinic has been involved in once-through cooling issues for about ten years now with respect to a variety of different plants along the coast, so we don't represent any particular group. We've worked with everyone here at the table as well as other groups. So I'm not going to come at it strictly as, you know, what would your group think, but trying to think more broadly about the coalition of folks who are interested in these issues.

And I guess I struggled a little bit with these questions, but just on the -- Wait. Let me just say one other thing is that on the air issues, it's very unfortunate that NRDC isn't here because I mostly have been working really on the water side.

And from what I understand about the situation in the South Coast, that is a very difficult. My sense is that that somehow is going to work itself out. I wish I had NRDC to talk about that a little more. But within, you know, a relatively short time, we're looking at a phase in of a policy over the next, you know, ten or fifteen years, and I think there are a lot of other things driving the resolution of the South Coast issue.

COMMISSIONER BYRON: I'm sorry. They're not here either. It's going to work itself out? We would really like to hear from them.

MS. SIVAS: I just don't think that the once-through cooling is going to drive the resolution of that issue. I don't know what that resolution is going to be, but what I'm concerned about is not getting most of the once-through cooling momentum we've got going off track because we had one really difficult issue in the South Bay. And I think there was talk this morning about you may have air problems in other districts, too.

I don't think they'll be anything, from what I understand, anything like what's the tangle that's happening in the South Coast Basin so, you know, I really hope that we -- that the state -- I'm very appreciative that the agencies have come together to try work this through because I think everyone here is concerned about grid reliability as well, and we have to figure out how to sequence this going forward.

I guess my message was just that, you know, hopefully we don't throw out the baby with the bathwater because the State Board has been working for several years now trying to put a policy in place, and it may mean that the pieces move a little bit but hopefully we don't just delay.

Beyond the air issues, I think there are minor issues related to alternative cooling. Ones that we've often faced in some of the projects that have been considered are aesthetics and green use issues. And I think my sense is that those issues are not of a magnitude of the ocean impacts and green life mortality, and those issues even EPA, which studied these issues for a number at a nation level but, nevertheless, looked at all of these issues in their rule making and concluded that those issues were negligible compared to the marine mortality that everybody knows is going on, and that's why they promulgated a rule that was fairly stringent going forward.

There are small issues to be worked out, but I don't think it's -- I think it's a false dilemma of it to say that there are tradeoffs of the same magnitude once you get beyond the air issues in the South Coast Basin.

MS. HAREN: Yeah. I would also like to agree with what Debbie said, and hopefully I don't know if our colleague from NRDC will make it here. But if not, we'll definitely follow up with them and encourage them to submit their comments in writing so that you can have their input as well.

I also agree with Debbie that we don't believe that we have to choose between protecting our water or protecting our air. I think in terms of achieving the various goals including reducing marine life mortality and protecting air quality that we actually view phasing out once-through cooling, if done properly, as a way to achieve both of these goals.

I know there was a report from CA ISO a couple of years ago noting that the majority of the old steam generators using once-through cooling have higher greenhouse gas emission rates than newer plants and that, you know, many of them are beyond their expected lifespan already, so we really view this as an opportunity through the proper planning to achieve multiple goals.

And we, you know, trust that the agencies responsible will do that, and we're encouraged that the agencies have been meeting very diligently and working through these problems. And we don't believe that balancing how to implement these goals and achieve other goals means that we have to sacrifice any of them. Just as Joe said, we advocate full implementation of the Clean Air Act and the Clean Water Act. And again we are here willing and able to assist the agencies in any way that they need to help to do that.

One thing I just wanted to mention, two things. One is that today earlier we heard some specifics about CA ISO's grid reliability research, but we didn't hear about the State Board and Ocean Protection Council. They co-funded a grid reliability study that was conducted by Jones and Stokes. And I would just like the opportunity to hear how the State Water Board is going to be taking into consideration the results found in that study as to what CA ISO is saying. So that study was released publically, is very detailed, and was funded by taxpayer dollars.

And so it's concerning to me that we didn't hear much today about that study, and so I'm eager to hear how the State Board is going to be or taking into consideration that report. And if there are issues with that report, we would very much like to hear them in a public forum so that we can understand them because we appreciate all the work that CA ISO has done, but so far we've just seen some PowerPoint presentations online and today and we haven't seen the details of that report. So to the extent that some of the conclusions differ between what CA ISO is concluding and what this other grid reliability report is saying, it just would be nice to be able to understand where those discrepancies are.

And then my last thing was just to introduce again Bill, and just to clarify and point out that he is here today on our request. He's a consultant and so he has a lot of other expertise that California Coastkeeper Alliance doesn't have, and also we appreciate him being here.

MR. POWERS: Thank you. A couple of comments to follow up and a little bit on my background. I'm currently working on two nuclear system retrofits projects, one in Connecticut and one in New York. These units are the same size as the Diablo Canyon units and the SONGS units, and I was involved in the Morro Bay cooling system CEC process evaluation, as well as Palomar Energy.

And I'd like to reiterate the comment about ICF Jones and Stokes. You heard the president of ISO talk about a $5 billion cost to meet with transmission and the retirement of the Southern California coastal plants. Jones and Stokes indicates that we can retire all of our OTC boiler plants for potentially as little as $135 million in transmission upgrades. That's almost a 50 to 1 difference is estimates on transmission costs to do this.

And I think a couple of the commentators from industry made some very interesting comments that I agree with, that you've got a ten, twenty, or thirty-year-old car in the garage that works fine and is a very low cost to operate. And with a cooling tower retrofit, you can use it as reliable peaking power for many years to come.

And the other report that was mentioned that was part of this Ocean Protection Council/State Water Resources Board state-funded was the Tetra Tech report. They indicate the cost to retrofit a boiler is about $150 a kW a cooling tower. The industry representative, I don't recall his name, said $125 a kW for his fleet of

4,000 megawatts. Well, that's just about the same, so we seem to agree that the cost of a cooling tower retrofit on a coastal boiler at $125 to $150 a kW is in the range of one-tenth of what it would cost for LMS100 peaking gas turbine installation. This is at least $1,000 a kW.

The same can be said of the combined cycle project, Moss Landing combined cycle and Haynes. The Tetra Tech report estimated $70 a kW for the refit to a cooling a tower. Cost for combined cycle new capacity there $800-plus according to the CEC, a factor of ten greater.

The nuclear plant -- I work a lot with nuclear plants and I don't know if the PG and E representative is still here, but I think he said $4 to $4.5 billion to retrofit it.

DR. JASKE: That's correct.

MR. POWERS: Well, the Tetra Tech report said $700 million. The project I'm working in Connecticut, which is the same size unit, in 2001 at Dominion Nuclear, the company estimated $126 million to retrofit it. The cost should be $200 to possibly $400 a kW. A new nuclear plant is minimum $7,000 a kW, a factor of 20 greater than retrofitting these nuclear plants.

And another comment to make is those plants are in the process of their steam generators are being retrofitted at both Diablo Canyon and SONGS. These are $700 to $1 billion projects that the utilities did not bat an eye about doing because they want to keep the plants running. And the trade press has indicated that they have done spectacularly well on I think Diablo Canyon 2, 69 days to do a searchable opening of the reactor housing and change out the stream generators. If it is mandated, it will get done, and it will get done effectively and fast.

And again, I just want to reiterate on this point that -- or one other point. Despite comments in here that we need all of the coastal OTC plants, we did see a presentation from the CEC today talking about resource adequacy contracts showing essentially none of these coastal or nonnuclear plants are under any type of resource adequacy contract from 2013 forward. Others know no one at the state level is saying we have to keep these plants operating. And it should be either they can compete or we need them and we retrofit them at ten cents on the dollar so they continue to provide reliable peaking power. This is not complicated, it’s not expensive, and I don’t really see much of a tradeoff. Thank you.

DR. JASKE: I can offer clarification about the chart in Mr. Vidaver’s presentation. The current resource adequacy process only requires load serving entities to identify the resources that just satisfy their obligation in a sort of stylized “year ahead” process. It has been the practice that some load serving entities enter into multi-year forward contracts because it essentially is cheaper for them to secure, you know, the services of a generator by doing so as opposed to just a set of serial one-year ahead contracts.

So that display of information is the compilation of what in effect is voluntary contracting forward because it’s cheaper for the ratepayer. It shouldn’t be construed as meaning that there isn’t a need for those plants, you know, in years forward. Just that that’s the level of contracting that exists today under this resource adequacy process and the voluntary multi-year forward contracting arrangement, but it is a better deal for the ratepayer.

MR. POWERS: Does that mean that the $4 to $4.5 billon comment was unrelated to the actual cost of retrofitting Diablo Canyon with cooling towers? I didn’t quite follow. The number stuck in my head, but I did not follow that it was -- I followed it as directly connected to the retrofit of Diablo Canyon.

DR. JASKE: I believe that’s correct, but that’s a cost he was indicating that would be necessary because they anticipate using that plant available to the -- Let’s put it that way. Whereas, the contracts with all the merchant plants there isn't yet a mechanism that requires in the long run of capacity contracts beyond just a one-year ahead process.

Mr. Lueze actually referred to the desirability of having, you know, a further forward capacity of market or a capacity requirement because that would bring more ability to the merchant generators to sort of understand their role going forward, but it doesn't exist as of the moment.

Well, let me then turn to question two, and you know sort of observe that in particular the plans put forward by the PUC and Energy Commission to ARB and built into their 8032 scoping plans called for, you know, very high levels of energy efficiency in renewables and so that tends to diminish the amount of fossil generation needed.

Do you anticipate your organizations, you know, anticipate, you know, more than those levels or do you think that, as outlined in the ARB scoping plan, that that's a good faith effort to sort of maximize the use of those resource types and diminish the amount of fossil generation necessary?

MS. SIVAS: So I'll start briefly. As I noted before, since I don't represent any particular organization, this question and the next one were a little difficult for me, but let me just respond to it this way, and that is on once-through cooling issues, we've worked with a coalition of groups interested in bringing issues. We also work with groups who are very heavily involved including NRDC, one of them, on AB 32 and greenhouse gas emissions.

And my sense from all of that work is that there probably are things that people want to come forward with. Having solar on everyone's rooftop was an interesting suggestion, but you know I'm not prepared to speak to those today because I think those groups need to speak for themselves.

But I wanted to just get back to I think an issue that you raised when Joe was here, which is, you know, are these groups working together? And I think the answer to that is yes. And I think from what I've seen, the groups have been very thoughtful.

So you have folks here at the table who are mostly working on green issues, you have other folks interested in air issues, other folks in particular on greenhouse gas issues, and I think there is a lot of discussion that the environmental community is trying to do across these subject matter areas recognizing, you know, that they interrelate in various way. And so I do find that a hopeful sign and that we're not going to get groups in silos based on, you know, their substantive expertise, but I think everyone recognizes the climate change issues are really very paramount these days, and that folks are trying to work together,

So it’s a little bit off point with your question, but I just did want get in there that I don’t think the groups are thinking only about the substantive issue but really trying to think more broadly across the media and across the, you know, like NRDC has additional things to bring to the table in energy efficiency and demand side.

MS. HAREN: So again, we focus mostly on clean water and marine protection, so we have not been involved with -- to the extent that -- to extent with how it plays with water conservation and water supply and once-through cooling, so we haven’t specifically been advocating. So to answer your question of whether or not we think that is sufficient, I don’t have the answer to that. But I can also say that we’re not a group that would go advocating for anything different with the greenhouse gas emissions because we don’t work on that.

But that said, we are working very diligently with water conservation, water recycling, and other policies that we feel will really help to reduce the amount of energy that California spends on conveying water, which is something that Joe talked about. And we’ve been working in concert with the State Water Board.

And you know I think that everybody pretty much on the planet at this point realizes that global warming is an issue and that it’s not something that’s our environment. And so we’ve been thinking very hard about how we can promote policies to both protect our water and hopefully reduce the energy demand and thereby reducing greenhouse gas emissions. So I would say that, you know, we’re really proud of all of the work that California has been doing and that the agencies have been doing, and we’re supportive about it and just trying to move forward as we can on the water side of things.

So I’m not quite sure if that answers your question, but that’s the best I can do from my water side.

DR. JASKE: Bill, anything you want to add to that?

MR. POWERS: A couple of points, and one isn’t directly related to greenhouse gases but it was brought out in the ICF Jones and Stokes report that between 2001 and 2008, we added in California 7,000 megawatts of generation. And at the time a year ago, there was at least 2500 megawatts in construction, so approximately at this point I would assume about 10,000 megawatts of generation added. Whereas, today it almost seems as if we’re talking about a static environment where these plants are part of a null set equation.

Going to the greenhouse gas issue, in 2008 the CPUC initiated a rule that the utilities must now achieve all cost-effective energy efficiency. And the graphs that they produced as a result of that ruling show our energy demand per year dropping between now and 2016. The target in 2020 may be 15 percent reduction in gigawatt hours per year. Demand response, without taking into consideration central air conditioning or air conditioning issues, stayed flat for ten years. If we achieve these targets, there is no -- the context of this discussion isn't with relentlessly rising demand. The context is dropping demand and at worst case flat peak demand but probable drop in that as well.

Talking specifically greenhouse gases, the California Energy Commission is at a point of potentially making a historic decision in a peaking power plant case in Chula Vista, the Chula Vista energy upgrade project where May 27th the CPUC Commissioner will be voting on a denial of 100-megawatt peaker plant. One of the elements in that denial was that the applicant did not evaluate to any detail what the CEC is at least identifying as a cost-effective photovoltaic alternative to the peaker plant.

Presumably if that denial holds, what it means is that every future peaking power plant, and since these once-through units are basically being used as peakers, the nonnuclear plants, would be -- the litmus test would be could you replace that capacity with photovoltaics? And so I think the CEC is going in exactly the right direction in maximizing the deployment of urban photovoltaics as just a new solution to an energy supply problem.

DR. JASKE: I think I heard earlier today some comments that sort of the capacity in the peak wasn't itself, you know, a sufficient replacement for the capabilities of these plants. That, in fact, there were needs for the flexible plants to deal with the intermittency of wind and you know the load itself. So did you -- were you here to hear that and do have any comment about that distinction between, you know, photovoltaic versus a dispatchable plant.

MR. POWERS: Yes. You do not need to backup photovoltaic power with gas turbines. That is a fallacy. And I think that the press nationally that looks at this like Public Utility Fortnightly is coming out with comparative studies showing that when you really need the power, which is hot, sunny days, you can rely on the output of the PV systems. If you desire to match the output profile of a summer day, you can add a limited amount of cost-effective storage and rely on PV systems, I'm distinguishing them from wind systems, rely on them for summertime peak power.

And I think that the issue of backing up wind power with a gas turbine just begs the question, if we have adequate capacity today to meet our power needs, why would we be building a new generation of peaker plants to backup wind turbines? Those wind turbines would be cutting into existing capacity and we will backing off the fossil units. We won't be -- We will not have a need to duplicate the nameplate of wind turbines with gas turbines, and I think that is an important point because there's a lot of talk about adding a lot of capacity to back the renewable energy. I don't think that's the way it should be handled in a world of declining electricity demand.

MR. MANSOUR: Mr. Jaske, I really come up to differ. Put it this way, you have the data that is, I'm afraid to say, very misrepresented, and I can go through every line of it that I would suggest that you check it.

MR. POWERS: What data is this?

MR. MANSOUR: Well, let me just go through one by one. First of all, let us just understand there's a difference between energy and capacity for energy and demand. Demand has been increasing. Actually, in April just last month, we had three days of above usual temperature, and we recorded at ISO the highest air load demand our end.

So there's a difference between demand and energy. Yes, there will be more energy especially from the -- as the 20 percent renewables come in, but the peak -- summer peak heat phase that we're talking about, the performance of wind at the peak time was five percent or less than the energy capacity. So you point out, no, you don't need to have this duplication. That is not a duplication when there is primarily an energy source and not a capacity problem. So that is still just (inaudible). These are facts. These are scientific facts. I'm not talking about the debate between reasonable people. I'm talking about scientific facts backed by real data.

The second thing is that you mentioned that someone has $1.7 -- $117 million to fix all the transmission constraints in the system. Frankly, if you have the name of that person, I'm sure there's some kind of big sale or something like $117 million and let them fix all the stuff in the state as you're saying.

Let me just give you some data on the cost that actually are things that are underway. The project that was offered in the retirement of unit 3 of Potrero was $450 million cable for transmission. And the cost of

Jefferson Martin 230 kV, which is in part resulting in the retirement of the Hunter's Point, was $230 million. Potrero and Hunter's Point, 115 kV cost is $100 million. These are costs that are already incurred to replace some of the local capacity needs by transmission.

So, you know, for someone to come and say all of those locations can be replaced or done by $117 million that is a severe misstate of the facts on what the cost of transmission is. And if that were the case, we wouldn't even need OTC. Every time I'm going to sign one of those generators to actually pay them to stay, we compare their costs to the actual cost of transmission that would actually get rid of them. And in every case, they are much more cost efficient than putting generators in, so that is another one.

The second thing is you have seen the static that there's 15,000 megawatts or so of OTC capacity in the state. Replacing that capacity -- We're not talking about the local level now. You heard the people talking about resource adequacy for the system as a whole. Replacing 15,000 megawatts of capacity, even if we say that some of the demand response and all of that will reduce it even a few thousand, you're still talking well over 10,000. Now the replacement of that capacity, since you still need it, is even not counted in $4 or $5 billion, and it is significantly more than that right now. So we're talking about just the transmission cost and not the replacement cost of replacing the capacity.

So we're all trying to solve the issue and we're all trying to not put cost entirely as a reason not to proceed. In fact, it is the opposite. But to actually state facts like you just mentioned, which is totally off, (inaudible) I just stand to differ. And that's just kind of discussing along with these of lines of numbers it does not -- really all facts show that is not true. For me, it's not helping.

DR. JASKE: You care to respond?

MR. POWERS: And I think this is -- Mr. Mansour brings up a very important point, which is the environmental community is working with the ICF Jones and Stokes report -- reliability report. If the ISO doesn't have it or hasn't read it, that's a problem because what that reports states is that with a phase-out over the next years, we can retire all of the coastal OTC boiler plants. And what we would need is a minimum upgrade -- transmission reinforcement upgrade, a value of $135 million.

The ISO may disagree with that report and those numbers; however, that report is much more detailed than anything the ISO has put out to backup their claim of a $5 billion expense to replace with transmission the retirement of OTC boiler plants in the South Coast. And so I think that in some ways we're getting where we should be, is that ISO needs to read ICF Jones and Stokes, needs to critique it, needs to present their case so that we can find the truth of the matter.

MR. MANSOUR: As I said, sir, if you have someone that is willing to take $117 million and solve all those problems, I am sure I can get all of us together and write a check for $117 million and solve them all.

MR. POWERS: I will see you at five p.m.

COMMISSIONER BYRON: Gentlemen, I'm hoping -- Thank you both very much, very good interaction. Let's try and get back to answering these next couple of questions or maybe we only have one left, Dr. Jaske, and then we'll open it up for public comment.

DR. JASKE: I think, yes, we are basically down to question four, and as I indicated in my back and forth with Mr. Geever, that it's written and it's probably not as clear cut as it could be. So it was originally intended to contrast the March 2008 notion that most of these plants would have to retire or they would have to comply, and I guess it's the super position of the staff's opinion that they would, in fact, retire by 2015. And that as that date grew closer, it would be realized as not feasible and, therefore, it would be pushed back. So there was the appearance of near-term compliance date.

Now contrast that with this effort over the last six months is emerging in which it might on its surface show more protractive compliance but it's at least more backed up with firm specifics for the various plants, you know. How does that -- do you react to that sort of contrast?

MS. SIVAS: Thanks. Yeah, I think as Mr. Geever said, you know, a lot of us have been at this for long time. And so I think if we're talking a year here to two on the margin, there may well be some value to looking at it in a way that makes sense of it, you know, but we're not five years or ten years down the line and having to push off things because of assumptions that we made today and we're not realistic.

So, sure, I think if we're all worried about grid reliability, it seems if a policy is based on trying to look at the system as a whole and deal with grid reliability rather than the State Board's original proposal, which was based on the capacity factor for a plant, I think that, you know, that makes a lot of sense there, you know.

As Jeff said, we haven't even seen what that might look like. It sounds like it won't look dramatically different. Certain things may shift a year here or there. But my own view is that the key is really putting -- the key here is to put a policy in place and have the industry working towards that policy, and I think that has been the biggest problem.

Even as you know, there's been litigation at the Supreme Court and some uncertainty over the federal policy, and the state has stepped in and is trying to bring I think some order to what has been a little bit chaotic at the federal level. And I know that dealing with the individual Water Boards the concern is always we don't know what the policy is, or where the policy is going, we're trying to interpret this.

So what we've been pushing is let's try to create a realistic policy, put it in place, and create the incentives and milestones for the industry to be aiming at. I would say, and I think it was confirmed by the last panel that was up here, is that we're looking ultimately at retiring some of these plants probably because they're quite old or repowering.

And in every case, almost every case where the companies are talking about repowering, they are actually looking at alternatives to once-through cooling. And I think that's a lot because they're seeing the writing on the wall. And I would say ten years ago when we first got involved, that was not the case, and I think sort of the policies at the federal and state level are really driving that market.

So I think the key thing is to try to get something in a reasonable timeframe in place. And if it's built around the agencies' judgments about grid reliability and how put those pieces of the puzzle together, you know, I think that that's something that can be workable.

I mean I guess I would say the one thing is, if we don't get a policy in place, what you're likely to see is right now we have a number of coastal plants that are on kind of long extensions of their Clean Water Act permits, which those are five-year permits, and they're supposed to be renewed every five years. And they're supposed to actually ratchet down technology because the Clean Water Act is a technology forcing statute. And so I think what you're going to see, if you don't get a policy that's in place with some implementable dates, you're going to probably see more litigation around the individual plants, which really doesn't do any of us any good on either side of the equation.

MS. HAREN: Thank you. So again, we obviously haven't seen the exact proposal and what the dates are, so I can speak to the specifics.

But just generally speaking, I just wanted to underscore something that Mr. Bishop said earlier, and the fact that this type of massive fish kill would not be tolerated by the State Board for any discharge. And the truth is that an untold number of marine species are being killed, and we're also facing, you know, the decline and collapsing of several of our major fisheries, and so this is obviously an important issue.

It's also important to note that peak larval abundance corresponds with -- well, it usually happens in the summer, and that corresponds with, as you've heard, when some of these plants that aren't used very often but when they are used they're used during the peak larval abundance, so it's important to note that.

So with that backdrop, we think any undue delay is not going to be beneficial in any way. But we do agree that proper planning and timing is really important. We also strongly believe that deadlines for compliance are critical if we're going to achieve these goals.

So we've been encouraged that the interagency working group has been working together, and really look forward to seeing the State Board's policy come out. I think that, and I hesitate to say this, but the exact deadline is not as important to us as the fact of having a policy in place with a deadline.

So hypothetically, let's say we have a policy that has a ten to fifteen-year phase-in approach. It's a big difference for the fish if we pass that policy today or in 2009 or is we pass it in 2011. So ten to fifteen years from today is a lot different than ten to fifteen years two or three years from now.

So I would say that, you know, we recognize what a complex issue this is. There are a lot of moving parts, and we really appreciate all the work that the State Water Board done and all the agencies here today. So if and when we see the policy and comes out and it's, you know, well supported with a lot of facts and there's deadlines in there that are supportive for why it's going to help grid reliability and also, you know, end the killing of these marine species as soon as possible, then that's, you know, something that we're going to support.

DR. JASKE: Mr. Powers?

MR. POWERS: Just a couple of comments. One is the two nuclear plants that use two-thirds are the once-through cooling water along the coast, and we do have one plant in the United States, a nuclear plant, that was retrofit from once-through cooling to cooling towers effectively -- cost effectively at less than $70 a kW in 1999 dollars.

And as I mentioned earlier, Diablo Canyon and

SONGS are already conducting more costly and much more invasive retrofits of their core systems and doing it effectively and doing it very quickly. And that the nuclear plants must be front and center in the discussion about the cooling tower conversions.

And I think that the comments that have already been made about the boilers that if the state is not identifying the once-through boilers as under resource adequacy contracts or under some concrete mechanism that tells us that these plants are really necessary, then they should compete. And if they cannot compete, they can shutdown. And if they are necessary, they can be retrofitted very cost effectively relative to new capacity with cooling towers.

DR. JASKE: All right.

COMMISSIONER BYRON: All right. Thank you, Dr. Jaske. Thank you very much, panelists. I hope you'll stick around for the public comment as well.

MS. KOROSEC: Commissioner Byron, we do have a couple of questions from the web.

COMMISSIONER BYRON: Okay.

MS. KOROSEC: And they're just strictly on this panel.

COMMISSIONER BYRON: Please.

MS. KOROSEC: We should do that before the panelists leave. So from Chris Williamson, we have at what point are the concerns of local government taken into account related the continued use of OTC plants and their jurisdictions and the Coastal Commission? Oxnard has two OTC plants and SCE is now adding a peaker plant and would like to consider the eventual removal of the OTC plants.

COMMISSIONER BYRON: They are to answer that from our panel?

MS. SIVAS: Well, it’s probably better answered by some of the agency folks. I mean I would just say that there is -- there is a process, as we heard this morning, where the Coastal Commission and the Energy Commission work in cooperation and also look at local land use issues. And I think it was mentioned here today that Morro Bay is an example where the city was involved as well. But I’m obviously not the expert.

MS. KOROSEC: The next question we have was from Eric Miller. We’ve heard about PM10 issues and occasional references to CO2 emissions. Given the increase in emissions that would occur with the transmission away from OTC to alternative cooling, how can we reconcile these increases with the both the goals the AB 32 and the ever increasing body of literature linking CO2 emissions, climate change, and global declines in marine resources, which have all outweighed any effects of OTC?

Examinations of long-term data studies in the Hudson River, Chesapeake Bay, as well as Southern California have declines in marine resources largely linked to climate change and associated oceanographic coursing. How do we as a state reconcile the desire to end OTC with the potential to increase global stress on marine communities further exacerbating the current problems marine resources face?

MR. POWERS: I can answer that. I think the question is if you retrofit a coastal boiler from OTC to a cooling tower are you going to be having a significant impact on greenhouse gases and climate change. And my response to that would be I consider that if you -- cooling tower retrofit may impose one percent to one and a half percent efficiency penalty on these units if they're operating five percent per year.

The amount of additional air pollution that will be emitted will be a fraction of any major source trigger level in any of the district where they're located. And so my perspective on -- Yes, there will a very small ancillary increase in emissions, but the benefit of eliminating the once-through cooling is of greater benefit than that arguably de minimis increase.

MS. KOROSEC: For Ms. Haren and Ms. Sivas, you mentioned that the air emission question is not a significant concern, but at a recent January '09 US Wildlife Service/US Geologic Service meeting on climate change and the West Coast Marine Resources painted a grime picture relating to CO_2 emissions and that they're growing faster than the IPCC worst-case scenario of ocean acidification, biogeographic shifts, sea level risk, and other climatic issues based on recent research. In the most recent research, it indicates climate changes accelerating beyond the IPCC worst-case scenario due to CO_2 emissions. Would you still say that these emissions are not a significant concern for marine resources?

Representatives of the West Coast Governor's Agreement on Ocean Health distributed questionnaires asking for ways to integrate all climate changes and all marine regulations analyses due to its importance.

MS. SIVAS: So I'll just start and just a point of clarification. I hope I didn't say it and I didn't to say that emissions were not a significant problem, both PM10 emissions for local populations in the South Coast and elsewhere and also obviously greenhouse emissions.

I think what I was trying to say is I'm hoping that those issues, which having grown up in the South Coast years and years ago now, it was a problem even then, and the hope is that all of the wise minds that have gotten together in this room and elsewhere work that out.

My point was merely that the resolution of those issues should not drive the policy throughout the state on once-through cooling, and maybe that through a grid reliability approach to the problem, we start with other areas of the state as the South Coast issue gets worked out. So I hope no one took that to mean that they're not significant air emissions. They're obviously quite significant.

MS. HAREN: It's also addressed to me. I also never meant to imply that it wasn't a significant issue. Obviously, it is. We are concerned about global warming and the impact on the marine environment as well as everything else.

I also was answering a specific question that was posed about tradeoffs. And our belief is that there don't have to be tradeoffs, that we can both enforce the Clean Air Act and the Clean Water Act. And that, in fact, because of many of these plants are older and less efficient and have higher greenhouse gas emissions rates that some newer generation, that it's our hope that solving the once-through cooling issue will also give benefit to reducing some greenhouse gas emissions.

MR. POWERS: A point on the PM10 issue. Just as a practical regulatory matter, San Diego County APCD, South Coast, Ventura, and Bay Area, the cooling tower permitting in those districts are exempt from permitting requirements. And at least from an administrative standpoint, the cooling towers can move forward on that basis.

One of the generator commentators mentioned that they couldn't put a wet tower at Moss Landing because the district would have required PM offsets. Those PM offsets are readily available through road paving. Both Morro Bay APCD and San Luis Obispo APCD where Diablo Canyon is located allow low-cost road paving to offset emissions from the facility and indicated that that would be allowed in the case of retrofits at either of those facilities as well.

COMMISSIONER BYRON: Get those cars to stop driving on those roads. All right. Ms. Korosec, you have some additional public comments. Can you give us an idea of how many you have there?

MS. KOROSEC: I have two cards only.

COMMISSIONER BYRON: Okay. That does not limit anyone else that wishes to speak.

MS. KOROSEC: I see there's two other hands going up out there.

COMMISSIONER BYRON: You can probably assume there will be a few more.

MS. KOROSEC: I would imagine. So the first card is from Mark Turner, Vice President of Competitive

Power Ventures. Second is from Rory Cox, Pacific Environment. I guess we lost Mr. Cox.

MR. COX: No.

MS. KOROSEC: Go ahead and come up to the podium if you wouldn’t mind so you can get it on the record.

MR. COX: Thanks a lot for considering this highly complex issue.

COMMISSIONER BYRON: Please identify.

MR. COX: My name is Rory Cox. I’m the California Program Director at Pacific Environment. And I did just want to reiterate what Mr. Powers mentioned about the Chula Vista proposed decision and the historic implications of that in terms of the viability of PV solar to replace peaking generation. I think that’s -- I think that’s our future. I think that’s the future of this discussion, and I’ve heard very little about it today. I think in the past there wasn’t even a meeting when the word solar was ever uttered, and I think that’s overlooking a huge solution to --

COMMISSIONER BYRON: All right. We’ll start every meeting from now on right after the Pledge of Allegiance we’ll say solar.

MR. COX: Thank you. And also in terms when we’re talking about costs, you know we don’t talk about costs of asthma and the public health costs. And what I heard a lot of was trying to, you know, get around the air pollution laws in the South Coast region by, you know, getting more permits, and I think there's a human level that was just missing from the discussion and those costs of public health on building more power plants. And we need to add that into the discussion.

The cost of global warming, you know, Nicholas Stern put out his groundbreaking study that demonstrated that was going to take a huge hit out of the world's economy if it goes unchecked. And that's the case whether the power plant is -- whatever kind of power plant it is. If it's fossils, it's going to cause global warming.

Another thing I just wanted to point out was the PUC's report on the 33 RPS goal. The only way we can meet that is no new fossil generation, and that came from the California Public Utilities Commission. So all of these problems that we are facing there are solutions that I think aren't being discussed enough. And I didn't really hear a lot about it until the last panel. Again, I think we need to put that in the mix a little bit more, so thank you very much.

COMMISSIONER BYRON: Thank you, Mr. Cox.

MS. KOROSEC: We have Steven Kelly, Independent Energy Producers Association.

MR. KELLY: Thank you. This is Steven Kelly with the Independent Energy Producers Association, and this is kind of a follow up because I do have some things to say about renewables and solar. As you know, IEP represents a number of different types of technologies in California, all the renewable technologies, as well as gas-fired generation, so we have kind of this what I hope to think is a more contemporary perspective about the ability to build generation in California.

And I'd like to speak about this issue of reliability, following up on Mr. Mansour's comments, and renewables as a replacement, particularly the replacement as I've heard discussed for possibly 19,000 megawatts of gas-fired generation that's in load center. And I want to put this in a little bit of context first, and most agencies are pretty much working on a 2020 context, the GHG goals are supposed to be, the RPS 33 percent goals is supposed to be couched in terms of 2020.

I just want to remind this Commission and I'm pretty certain you haven't forgot this that that's 12 years out. We've been running an RPS in California for eight years now, and we've gotten 800 megawatts of installed renewables, so the track record for renewables to not only meet new demand but replace the existing infrastructure is not very good.

And as I look forward and look out over the horizon as I work on the RPS statewide at the PUC and elsewhere, I don't thing the track record is posing a very good solution. As you all know wind, geothermal, biomass, solar thermal, all are difficult to construct in California, not only the permitting and siting of those facilities, but particularly getting the transmission in place. Most utilizes will admit or say that it takes seven to ten years to built transmission that will link into the renewables that would be this replacement technology for the kinds of resources that are supporting the system today. Biomass you can't even get to, so I don't think there's any prospect that that resource is going to be a significant replacement for the existing status quo.

I've heard it said that solar photovoltaic is going to be the solution. When I look at photovoltaics, and I've got members that are developing photovoltaics so we support this as a technology, I notice a couple of things. One, it's about $20,000 to install on rooftops. I think the public sector is subsidizing that about 50 percent. The cost to replace the 19,000 megawatts of generation that's being provided through these facilities we're talking about today is tremendous. We've done a calculation for rooftop PV, and the cost for that on a cent per kilowatt hour basis is anywhere from 25 to 40 cents a kilowatt hour.

We support this technology and we think it's something that's important for California, but the expectation that that this technology is going to be able to replace these other existing generation technologies is what I think very faulty assumptions particularly in the short term over the next ten to twelve years. The cost of doing it and the implementation impediments for doing it on homes is probably far too great to work on an assumption that it will be there when these existing generators are removed from their locations.

It speaks for the recognition that we really need a transitional program. Certainly, one that looks out at five to ten years and possibly more. We need to make sure from a reliability perspective that the lights stay on, that we have a mechanism to incent not only the new technology that the state wants, the renewables, but we can't do that in an environment where the lights -- we have grid reliability problems.

So I would recommend that we look at this as a program, a fix that needs to get in place, and transitional mechanism to do this with the expectation that perhaps we'll make a 33 percent RPS goal by 2020. I'll just observe that right now we've got a 20 percent by 2010, and we're probably at least three years behind on that goal, so we have a lot of work to do in the renewable world.

And the assumption that that is going to be the technology that is going to be there to solve the problems in the near term is not one that I think is well grounded in the facts of installation. So those are my comments.

COMMISSIONER BYRON: Very good.

MR. KELLY: Thank you.

COMMISSIONER BYRON: Thank you.

MS. KOROSEC: Do we have anyone else in the room who would like to speak? If not, let's go ahead and open up the phone lines. All right, the lines are open. If there's anyone on a call that would like to comment, please go ahead. Well, I'm not hearing anything unless somebody is having a hard time getting onto the phone. All right. I think that's -- We have no further public comment.

COMMISSIONER BYRON: Okay. I note that we're going to do -- we have Mr. Jaske down with some wrap-up comments; is that correct?

MS. KOROSEC: Correct, yes.

COMMISSIONER BYRON: So we'll finish with that. But before we do, I'd like to turn to the follow members on the Dais and ask if they have any final comments they'd like to make about what they heard today.

MR. ST. MARIE: Thank you, no. This has been very helpful. I will be briefing Commission Bohn about this and we will have subsequent discussions, and we will be back for more.

MR. MANSOUR: Again, thank you very much, Commissioner, for organizing it the Commissioner’s staff that has been also very helpful in a lot of ways.

One key point that I think that we got out of it I hope that we follow on it is involving the industry in the debate, not just the debate, but in getting the solution as well. From what we heard today is that they’re not necessarily -- it’s not necessarily that they just own facilities that’s been the source of the issue, but they’re also willing to be part from the solution, and I think we should follow on that offer.

Obviously, we were, at least the agencies in the ISO, were counting on some sort of incentives in the procurement process to at least encourage within reason the repowering of the existing OTCs, and I did not get a lot of ideas on how that can be achieved. But I think there’s movement in the industry including the generators and load serving entities will be very helpful to get us to some solution on that.

Two times I guess there was mention of a reference to a study, a reliability study that was done that was not by ISO with some representation of -- of other results. I recall only two, and I hope we can also include reference to anything else that was not -- that I don't recall, so maybe we should refer to those, one of them by the Energy Commission. I believe it was two years ago or so. It was a study to find options to all the plants to retire those plants. And the result of that study that I recall said whatever you retire, you need to replace it (inaudible). That was actually very kind of, you know, great. (Inaudible) you read that conclusion.

And the second one was by the Water Board for what was intended to be a reliability study that I read the result of it was an analysis of the various locations. And at the end, it said something to the effect that the local reliability issue is a very complex one and we're glad that the ISO is looking at is and not us. I mean the entity that actually did the study. That was the second one that I recall.

And there are others that actually gave solutions to -- the solutions as to the reliability issue that we would be more than happy to entertain. But the reliability issue when you talk about the computations and combinations of all of the facilities that we're looking and which one can be done when and where do they move to, and when they move to those other places in the state, how do they connect to the grid? There's virtually almost an infinite number of possibilities, and that is why we try to put out some case like bookends as to what the impact is, and then by all the suggestions that we'll try to narrow it down to a manageable size, a manageable level of things that we look at as we go ahead, you know, to try to give the Water Board some helpful suggestions as to how they can move forward.

Let me also reiterate that the ISO I can assure you that we aren't saying that this is a good policy or not good policy. We won't say that results are high or low. We will just say what it will take to fix and that's what we've been doing. So any data that we provide is along the lines of we're trying to help with the state policies to be committed, but we also will stand correcting any numbers or any statement that really are out (inaudible) misstates the facts. So with that, thank you very much, Commissioner, and the same for all the staff.

COMMISSIONER BYRON: Thank you. Thank you, Mr. Mansour. In fact, thank you, both, very much for being here. I guess we couldn't keep you away. We do a workshop called Options for Maintaining Electric System Reliability When Eliminating Once-Through Cooling Power Plants. Talking about reliability or taking plants off the system gets the attention of the ISO and the PUC.

And of course, this Commission, prior to my joining it, has made recommendations in the past in previous IEPRs to retire aging power plants. They're inefficient. I hope I'm not disclosing my feeling about these plants, but these boat anchors, these old dogs need to be retired, but we can't do it simply just by shutting them down because there are very strong linkages to other issues in addition to water.

There's obviously the priority reserve associated with air emissions in the South Coast and reliability that I mentioned earlier, so it's -- I think someone said this earlier today that it's one of the many issues and impacts on the environment, once-through cooling that is, that we must balance in the decisions that we make.

So it's extremely important to the work that we're doing in the Integrated Energy Policy Report. That was the original intention of this committee workshop today and, of course, it's also linked very closely to the rule that the State Water Resources Control Board will be promulgating. I heard very clearly they're moving forward on a fixed schedule and they expect the deadlines that we propose in a plan to be met.

I can tell you that the agencies -- the energy agencies are working very closely as part of the working group on this issue that's been established in addition to some of the other agencies that were represented here today. This is a big problem, and we're going to have to all work together in solving it. I learned a great deal from the participants of the various panels today, but we also know that this is tied up in court.

I was troubled to hear the comments of one of the last panelists that indicate that there may be more litigation. I don't think that was a threat. I think it was just the indication that if we don't do this right, if things don't move along quickly enough for those that have been waiting many years to see action, that we could see more litigation. We need settlements. We need that stuff to get out of the courts to help move forward on this because right now we have a lose, lose situation that's affecting public health in a very serious way and will be an impediment, notwithstanding Mr. Kelly's comments about how slowly we're moving on our renewable portfolio standards, but if we are not able to provide the kind of resources that we need to firm up renewables going forward, we're not going to be able to move forward in that regard either.

So we need to fix this problem. This agency is committed, too, and I know having met numerous times with my colleagues at the ISO and the PUC and also having met recently with a number of members of the State Water Resources Control Board and staff, people in this government are very committed to working on solving this and providing a reliability based approach so that we keep the lights but that we get this problem addressed in a timely manner.

So I certainly welcome the participants of -- all the participants here today. The panels were very good and very informative. You've all been very patient sitting through all of this. I think the staff did a very good job. I think we're going to end with some comments from Dr. Jaske. I ask him as kind of our in-house expert on this subject, and he's really been spearheading the working group to make closing comments that I think that we might all benefit from. Dr. Jaske, don't let me down.

DR. JASKE: I'll take about three minutes. Several times I sort of hoisted up the March 2008 proposal of the Water Board's scoping plan of 2015 for the low capacity factor plants as a rather unrealistic way to go about the problem. It doesn't really address the myriad of nuances that we heard about today. And I only did that because I know that Mr. Bishop is already convinced that that's not the right way to go, and our collaboration up to this point has given him a sense that we're going to try to deliver a serious implementation proposal to them very shortly.

He wants to publish his actual policy at the end of June or early July, and it will contain some version of our proposal, and we'll be able to put some of those specifics on the table that people were asking for and talk about it in some detail at the July 9th workshop provided his timing allows that. We don't want to steal his thunder, but we do want to provide an opportunity for the energy industry to dive into the details.

I think we did hear some sayings that caused to need to think at least here and there about our proposal. Clearly, the generator community is saying they can do some things that don't imply retiring all these plants. There may be at least some of them that are worth salvaging and some OTC reduction if not complete mitigation could be done in conjunction with preserving their life for another decade or so and maybe those options, you know, need to be examined. They may well be very specific to individual facilities. And so how to bring that perspective to bear in developing our plan in a sense, not in a sense, necessitates the cooperation of the facility owners in sort of making that kind of information known to us than just their oral statement today.

Clearly, the IOUs indicated there's ways in which there are those processes that can be modified. They're leaning toward the PUC in effect to figure out a means by which they take OTC mitigation into account in their selection of plants. And Bob Strauss made very clear that that's coming and maybe it will come earlier for the PG and E and San Diego areas where it's more clear cut than for Edison where everyone seems to agree that because of the South Coast air quality issues that at least is lagging behind the other two areas in time and probably ultimately in the tradeoffs between repowering existing facilities and trying to rely upon other technology to the maximum extent possible.

There's some push to act with this. Well, I shouldn't, as is frequently the case when we're talking among this community right here, we don't want to neglect the fact that LADWP is in a different situation. And we explored a little bit with Mr. Tharp the issues of their system and how their system has evolved over time and their own local reliability constraints. The Energy Commission staff will be pursuing those details with LADWP as quickly as we can.

We did hear that the Jones and Stokes Reliability Study, you know, needs to be paid attention to. And if it is flawed, the flaws need be expressed by the energy agencies so that that environmental community doesn’t continue to rely upon it as a source of information if it is, in fact, not supported by our views.

And we heard perhaps more than anyone else Ms. Sivas say, my words summarizing her point, we need an OTC policy stake in the ground and some milestones so that everyone gets the message that that’s the ultimate goal and can get on with the very complicated work of trying to figure out how to actually achieve that. But absent that stake in the ground, everyone keeps waffling back and forth about where we are going and when.

And I’ll just observe lastly that, as seems to always be the case, we had gigantically wide views about the nuclear plants, their roles, the cost to do refit, etcetera. And something more basic and fundamental appears to be necessary to produce a compilation of existing studies or reconcile the studies or do new studies that sort of brings a more universally agreed set of facts to the table.

COMMISSIONER BYRON: Thank you, Dr. Jaske. This issue will be taken up at the State Water Resource Control Board. We’ll be taking it up again on July 9th here in a workshop. Again, thank you for being here. We’ll be adjourned.

(Whereupon, at 4:35 p.m. the workshop adjourned)

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CERTIFICATE OF REPORTER

I, MARY CLARK, a certified electronic reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop, dated May 11, 2009; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in the outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 26th day of May, 2009.

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MARY CLARK, CERT*D-214

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